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MODELS FOR ELECTRICITY MARKET EFFICIENCY AND BIDDING STRATEGY ANALYSIS

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MODELS FOR ELECTRICITY MARKET EFFICIENCY AND BIDDING STRATEGY ANALYSIS

by

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Dissertation

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirement

for the Degree of

Doctor of Philosophy

The University of Texas at Austin

May 2005

To my family

Acknowledgements

I am truly grateful to my supervisor, Dr. Baldick, for his advice and support in this research. I would like to thank the other members of my dissertation committee, Dr. Mack Grady, Dr. Parviz Adib, Dr. Shumel S. Oren, Dr. Mircea Driga, and Dr. Surya Santoso for their guidance and efforts throughout. I own special thanks to Dr. Baughman and Dr. Grady for introducing me to this interesting research area.

This dissertation would not be possible without the generous help from Market Oversight Division (MOD) of the Public Utility Commission of Texas. I have been very fortunate to have the opportunity working as an intern in the division for two years. I not only substantially benefit from the knowledge of people there, but was also inspired by their dedication to their work. I would like to thank them, especially Parviz Adib and Tony Grasso for their patience, support, and friendship.

The experience at MOD also brought me the luck to have Dr. Oren in my committee. I really appreciate his illuminating insights and valuable suggestions on my research. I would also like to thank Dr. Mina Dioun at the Lower Colorado River Authority for her generous support and help.

Special acknowledgement and thanks are extended to Henwood Energy for supporting this research.

Last but not least, I would like to thank my family, especially my mother and my husband. They have always been there supporting me with their love.

Hui Niu

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Publication No._____________

Hui Niu, Ph.D
The University of Texas at Austin, 2005

Supervisor: Ross Baldick

This dissertation studies models for the analysis of market efficiency and bidding behaviors of market participants in electricity markets. Simulation models are developed to estimate how transmission and operational constraints affect the competitive benchmark and market prices based on submitted bids. This research contributes to the literature in three aspects. First, transmission and operational constraints, which have been neglected in most empirical literature, are considered in the competitive benchmark estimation model. Second, the effects of operational and transmission constraints on market prices are estimated through two models based on the submitted bids of market participants. Third, these models are applied to analyze the efficiency of the Electric Reliability Council Of Texas (ERCOT) real-time energy market by simulating its operations for the time period from January 2002 to April 2003. The characteristics and available information for the ERCOT market are considered.

In electricity markets, electric firms compete through both spot market bidding and bilateral contract trading. A linear asymmetric supply function equilibrium (SFE) model with transmission constraints is proposed in this dissertation to analyze the bidding strategies with forward contracts. The research contributes to the literature in several aspects. First, we combine forward contracts, transmission constraints, and multi-period strategy (an obligation for firms to bid consistently over an extended time horizon such as a day or an hour) into the linear asymmetric supply function equilibrium framework. As an ex-ante model, it can provide qualitative insights into firms' behaviors. Second, the bidding strategies related to Transmission Congestion Rights (TCRs) are discussed by interpreting TCRs as linear combination of forwards. Third, the model is a general one in the sense that there is no limitation on the number of firms and scale of the transmission network, which can have asymmetric linear marginal cost structures. In addition to theoretical analysis, we apply our model to simulate the ERCOT real-time market from January 2002 to April 2003. The effects of forward contracts on the ERCOT market are evaluated through the results. It is shown that the model is able to capture features of bidding behavior in the market.

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LIST OF ABBREVIATIONS

AEP – American Electric Power
AMP – Automatic Mitigation Procedure
AS – Ancillary services
BEM – Balancing Energy Market or BES
BENA – Balancing Energy Neutrality Adjustment
BES – Balancing Energy Service
BEU – Balancing Energy Up Service
BED – Balancing Energy Down Service
CAISO – California ISO
CCN – Certificate of Convenience and Necessity
Co-Op – Electric Cooperatives
CPL – Central Power and Light Company
CR – Competitive Retailer
CRE – Closely Related Elements
CSC – Commercially Significant Constraint
CSM – Competitive Solution Method
Entergy – Entergy Gulf States, Inc.
EIA – Energy Information Administration
ERCOT – Electric Reliability Council of Texas
FERC – Federal Energy Regulatory Commission
ICAP – Installed Capacity Market
IESO – Independent Electricity System Operator of Ontario (formerly called IMO)
IMO – Independent Electricity Market Operator of Ontario
IOU – Investor-owned electric utility
IPP – Independent Power Producer
ISO-NE – ISO New England
ISO – Independent System Operator
LaaR – Loads acting as Resources
LMP – Locational Marginal Pricing
LRS – Load Ratio Share
LSE – Load Serving Entity
MCPC – Market Clearing Prices of Capacity
MCPE –Market Clearing Price of Energy
MD02 – California Market Design 2002
MISO – Mid-West Independent System Operator
MOD – Market Oversight Division
MOU – Municipally Owned Utilities
NEM – National Electricity Market of Australia
NERC – North American Electric Reliability Council
NOIE – Non-Opt-In Entity

NETA – New Energy Trading Arrangement of England and Wales
Nord Pool – Nordic Power Exchange
NSRS – Non-Spinning Reserves Service
NYISO – New York ISO
NZEM – New Zealand Electricity Market
OOMC – Out of Merit Order Capacity
OOME – Out of Merit Order Energy
PARWG – Planning Assessment and Review Working Group
PCR – Pre-assigned Congestion Rights
PDS – Parallel Decoupled Solution
PGC – Power Generation Company
PJM – Pennsylvania-New Jersey-Maryland Interconnection
PRR – Protocol Revision Request
PTC – Production Tax Credit
PUCT – Public Utility Commission of Texas
PURA – Public Utility Regulatory Act
QF – Qualifying Facility
QSE – Qualified Scheduling Entity
REP – Retail Electric Provider
RgDn – Regulation Down Service
RgUp – Regulation Up Service
RMR – Reliability Must Run
RPRS – Replacement Reserve Service
RRS – Responsive Reserve Service
SB7 – Senate Bill 7
SCE – Schedule Control Error
SGIA – Standard Generation Interconnection Agreement
SMC – Simultaneous real-time Market Clearing
SMD – Standard Market Design
SWEPCO – Southwestern Electric Power Company
SFE – Supply Function Equilibrium
TCR – Transmission Congestion Right
TCRF – Transmission Cost Recovery Factor
TDSP – Transmission and/or Distribution Service Provider
TNMP – Texas-New Mexico Power Company
TXU – TXU Electric Company
WTU – West Texas Utilities Company

CHAPTER 1: OVERVIEW

1.1 BACKGROUND

During the last 15 years, the regulatory framework for the wholesale sector of the electricity industry has been replaced in many countries by forces of market competition in order to produce electricity efficiently and reliably. Currently, there are more than a dozen existing restructured electricity markets in the United States and around the world[1]. These markets vary in terms of the market organization, system operation, transmission charges, congestion management, market mitigations, and investment incentives. These differences are often motivated by characteristics of the existing systems (e.g., generation mix, network topology, and pool arrangement), historical realities, asset ownership, operational practices, and philosophical perspectives.

Although extensive effort has been involved in electricity restructuring, there is a continuing debate over various aspects of electricity market design. Each market has changed in some aspects because of various difficulties and problems experienced. Some markets have undertaken big changes, such as the California market and the England and Wales market. The California market ended its zonal Power Exchange and is implementing its new proposed market design 2002, "MD02." The England and Wales electricity market changed from a centrally dispatched bid-based power pool to the New Electricity Trading Arrangements (NETA) based on bilateral trading in a forward market. Other restructured markets, including the Electric Reliability Council of Texas (ERCOT), have changed more incrementally.

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[1] Restructured U.S. electricity markets identified by their Independent System Operators (ISOs): California ISO (CAISO); Pennsylvania-New Jersey-Maryland Interconnection (PJM); New York ISO (NYISO); ISO-New England (ISONE), Electric Reliability Council of Texas (ERCOT). U.S. electricity markets undergoing development or changes: California Market Design 2002 (MD02) and Mid-West ISO (MISO). Examples of international electricity markets: Independent Electricity System Operator (formerly called Independent Electricity Market Operator (IMO) of Ontario, Power Pool of Alberta, New Energy Trading Arrangement (NETA) of England and Wales, Nordic Power Exchange (Nord Pool), National Electricity Market (NEM) of Australia; New Zealand Electricity Market (NZEM).

The Federal Energy Regulatory Commission's (FERC) proposed Standard Market Design (SMD) to unify best practices in market design, and to enhance competition in electricity markets under its jurisdiction. Since it is impossible to recommend a solution that fits all situations, the SMD allows for regional variations. Currently every U.S. electricity market is seeking ways to improve market design based on its regional realities.

Underlying the growing debates over the appropriate organization of the electricity markets, there is a critical need for the evaluation of electricity market performance that are already operating and the understanding of market participants' behaviors. Before making any decisions on market design or revision, it will be helpful and instructive to evaluate the effects of the current policy.

The objective of deregulation is to supply electricity efficiently resulting in lower price by replacing the regulatory scheme for the wholesale sector with market competition. In a perfectly competitive electricity market, the market price should be the marginal cost of electricity production. However, if market competition is weak, electricity markets may fail to force prices down to the marginal cost. The ability to alter the market price from the competitive level is defined to be market power.

Even though a perfectly competitive market is the objective of the electricity industry restructuring, there is no such perfect market in practice. Many issues can contribute to market inefficiency, such as market design flaws, abuse of market power, and inherent engineering features of power system operations. Several characteristics of electricity markets facilitate the exercise of market power. These characteristics include: inelastic demand and the lack of timely responses by some consumers to price variations, limited transmission capacity, and the system engineering requirement that supply and demand must balance continuously. Some research shows that peculiarities of electricity markets can make a large difference in market power in electricity markets (Scherer (1990), Oren (1997)). Market power could result in market prices that deviate from competitive prices.

Because each electricity market has its unique features and policies, analyzing market performance and behaviors of market participants is still an open research area.

Given the historical structure of the electric industry, it is not surprising to expect big firms have more market power than smaller ones. During most of the 1990s, regulatory evaluation of market power focused on concentration measures, such as the Herfindahl-Hirschman index (HHI). Unfortunately, such measures are not adequate to indicate the exercise of market power in the electricity industry. The reason is that the electricity industry is characterized by highly inelastic demand, short-run supply constraints, transmission constraints, and extremely costly storage (Borenstein, Bushnell, and Knittel (1999)). In such circumstances, firms with very small market shares could exercise significant market power. The presence of transmission constraints presents further opportunities for exercising market power regardless of the degree of concentration (Oren (1997a), Cardell, Hitt and Hogan (1997), Baldick and Kahn (1997)). Therefore, the HHI index only is not sufficient for market power analysis in an electricity market.

Alternative ways to analyze market power in electricity markets have been developed, among which the empirical analysis and oligopoly game theory models are broadly performed. The empirical analysis approaches estimate the performance of market or a firm by estimating price-cost margin for a system or a firm. The oligopoly game theory models analyze firms' behaviors by developing optimal bid strategies for firms and evaluating the market equilibrium prices.

The reminder of this chapter is organized as follows. The physical characteristics of electric power and their roles in this dissertation are described in section 1.2. Empirical analysis approaches are reviewed in Section 1.3. Section 1.4 reviews the oligopoly game theory models applied in electricity markets. Finally, the contributions of this dissertation to the literature of electricity market analysis are summarized in section 1.5.

1.2 PHYSICAL CHARACTERISTICS OF ELECTRIC POWER SYSTEMS

Even though the electricity industry restructuring aims to replace regulation with forces of market competition, the operation of the electric power system has to obey physical rules of electric systems. The importance of engineering characteristics for the electricity markets has been addressed by Bai (1997), Oren (1997), Cardell, Hilt and Hogan (1997), Younes and Ilic (1998), Borenstein, Bushness and Stoft (2000), Stoft (2002), Baldick (2003), De la Torre, Conejo and Contreras (2003).

In this section, we first describe the major physical characteristics of electric power systems in 1.2.1. Then the importance of these characteristics and their roles in this dissertation are discussed in subsections 1.2.2 and 1.2.3.

1.2.1 Kirchhopf's laws and the transmission system

Different from markets for other commodities, electricity markets are highly constrained by the effect of Kirchhopf's laws applied to the electric transmission system. By the Kirchhoff's first law, the current flow into any node in a circuit equals to the current flow out of the node. The second Kirchhoff's law is that the voltage drop around any loop equals to zero.

Based on the Kirchhoff's laws, the produced power within an interconnected power system should equal to the consumed power within it. This is called power balance. Electric power is measured by Watts, which is the product of the voltage drop through an electrical element and the current through that element. The relationship between the voltage drop and current through an electrical element depends on the characteristics of that element. For a transmission line, the electrical current flowing through it equals to the voltage drop across the line divided by its impedance, consisted of line resistance and line reactance. The power loss through a transmission line equals to the square of the line current due to real power flow times the line resistance.

In order to operate an electric power system reliably, the system power supply has to equal to the system power demand, and the power flow through the transmission lines has to be within the transmission limits of these lines. The process to dispatch generators to meet the power balance within the system transmission capacity with minimal cost is called the Optimal Power Flow (OPF) process. The OPF process is the basis for the market clearing mechanism of electricity markets.

The engineering characteristics of electric power systems are not only very important for the market clearing process, but also are very important for structures of electricity markets. In subsections 1.2.2 and 1.2.3, we discuss why power balance and transmission are important for electric power system operation and electricity markets.

1.2.2 Importance of the power balance

Unlike other commodities, operation of electric power systems is complicated by the lack of economical ways to store energy. System supply and demand balance must be maintained all the time. Any imbalance between supply and demand will drive the system frequency to deviate from its standard level (60Hz in United States). When the system supply is greater than the system demand in an interconnected power network, the frequency will increase. In contrast, when the system supply is less than the system demand, the frequency will decrease. Here, the supply and demand balance emphasizes the real power balance. However, the reactive power balance is also important. If electric devices take out reactive power too much locally, voltage will sag in that area. If reactive power is injected too much locally, voltage will increase in that area.

Frequency and voltage are the two fundamental characteristics related to the quality of delivered power. If frequency or voltage deviates from their standard level above the allowed ranges, customers will encounter trouble with the power delivered to them. Every generator in the system must be synchronized with every other generator in the AC interconnection, which may extend over millions of square miles. The deviation of the system frequency may cause added wear and tear for some electrical machines. Synchronous motors run at a speed proportional to frequency. Many motors will run faster and draw more power when frequency increases. High voltage may cut the life of some electric devices. Low voltage can cause the under performing of some motors.

In order to provide power with high qualities, the system operator has to maintain the system balance all the time. However, since there are unpredictable fluctuations in system loads and generators, it is difficult to keep the system balance all the time. Ancillary services are very important to improve the system's ability to withstand sudden disturbances, such as a breakdown of physical component of the power system. If an operating generator breaks down, it may be hard to keep the balance between supply and demand. Then system frequency and voltage may drop. If they drop too far for too long, load must be shed to retain system supply and demand balance. However, if appropriate ancillary services are available, the lost power can be replaced by ancillary services. Then system operator will be able to keep the system balance without shedding load.

Voltage normally drops as power flows from generators to load. The more power flows, the more voltage drops. Usually the voltage drop through transmission lines may be able to be compensated by adjusting transformers. Injection of reactive power is another way to counteract the voltage drop. Some electric devices, such as capacitors and synchronous condensers, inject reactive power, which can cause the voltage to increase. Even though supplying reactive power does not consume fuel, it will reduce the ability of a generator to produce real power.

The system operator can purchase ancillary reserves through market mechanisms or contracts. The reactive power is difficult to transmit, because its transmission losses are much higher than the losses of real power. Normally, the system operator purchases long-term contracts for the service of providing reactive power. In addition, in order to maintain the system balance in real-time, electricity markets normally include a day-ahead market or schedule process, an hour-ahead market or evaluation process, and a real-time market. This structure of markets is helpful to tracking the predictable and large scale fluctuations in supply and demand before real-time.

1.2.3 Transmission network

Transmission network is also very important to maintain system balance and to supply electric power with high quality. Even when there is enough supply to meet demand, transmission network has to be able to transfer the needed supply to the load. Otherwise, the system balance still cannot be maintained.

Compared with other kind of networks, electric transmission system is very fragile. The flow through the transmission line cannot exceed certain level. Otherwise, overheat may cause the overloaded transmission lines sag permanently or even to melt. Even most high-voltage transmission lines have automatic relay protective devices which can take them out of services when the current approaches to a certain level, taking one line out may cause the cutting of other lines and disrupting services to some customers. It can also create voltage stability problems, which may result in black out of the system.

The transmission line limits depend on many factors. First, there are thermal limits, which are the heat tolerance threshold for transmission lines. Second, there are security limits, which can be the limits in case there is forced outage on another line in the transmission network (normally using N-1 security limits). Voltage limits and stability limits can also contribute security limits.

In order to maintain system reliability, the system operator has to check the transmission limits frequently. These transmission limits have to be ensured when the system operator dispatch generators within the system to meet system demand, which is called security-constrained economic dispatch. The resulted power flow on transmission lines should not exceed their transmission limits.

Since these special features of electricity systems have important effects on system and market operations, and behaviors of market participants (Berry 1999, Hobbs 1999, Smeers and Jing-Yuan 1997, Cardell 1997), this dissertation incorporates the electric transmission network into the market efficiency and bidding behavior analysis, which is a major contribution of this research. DC power flow model is used to represent the transmission network in models proposed in this dissertation. The DC model, which is to be discussed in detail in section 3.2.1, retains reasonable fidelity to the physical properties of electric power system. In the simulation of the ERCOT real-time market, the DC model captures the zonal congestion management process, which is to be discussed in 3.3.1 and 4.3.2. In section 4.4.1, the effects of the transmission network on the bidding behavior of market participants are discussed.

1.3 EMPIRICAL ANALYSIS

The objective of deregulation is to supply electricity efficiently resulting in lower electricity prices. In a perfectly competitive electricity market, the market price should be the marginal cost of electricity production and competitive firms should bid their marginal costs to the markets. The rationale behind the empirical market analysis is to estimate the prices that would result if no firm attempted to exercise market power, and to compare the estimated prices to the observed market prices. This approach has been used to the market performance estimation (competitive benchmark analysis) and firm's activity analysis.

1.3.1 Competitive benchmark analysis

The competitive benchmark has become one of the fundamental metrics for market performance evaluation. The basic idea behind the competitive benchmark approach is to estimate the price that would result if no firm attempted to exercise market power based on engineering models of generation costs. Comparing the observed or actual market prices with the estimated competitive benchmark prices could indicate how close an actual market is to the perfectly competitive market.

In the perfect competitive market, all firms are assumed to produce homogeneous, perfectly divisible output, and face no barriers to entry or exit; producers and consumers have full information, and no transaction costs are incurred. In the absence of scarcity, marginal cost of production will be the equilibrium price of a competitive market. Even though perfect competition is rarely encountered in the real world, it provides a benchmark against which to compare markets with different structures.

Mansur (2001) applied competitive benchmark analysis to the PJM market accounting for the unique features of the PJM market. He showed that market imperfections existed during the summer of 1999 in PJM and that at least one firm in the PJM electricity market likely behaved in a non-competitive manner in setting prices.

Borenstein, Bushnell and Wolak (1999) examined the degree of competition in the California market during June 1998 and September 1999. They found significant departures from competitive pricing during the highest demand period. However, no evidence of the exercise of market power was found for the winter and spring of 1999.

Joskow and Kahn (2001) considered the prices of emission permits and imports of electricity from other states to the California market to estimate the competitive benchmark wholesale prices for electricity in the California electricity market during the summer of 2000. They identified evidences of the exercise of market power during the highest priced hours of the summer.

Borenstein, Bushnell and Wolak (2002) decomposed wholesale electricity payments into production costs, infra-marginal competitive rents, and payments resulting from the exercise of market power. Using data from June 1998 to October 2000 for the California market, they found significant departures from the competitive pricing, particularly during the high-demand summer months. However, they did not consider the costs of transmission congestion or local reliability constraints in their estimates of the marginal cost of serving a given demand.

Bushnell and Saravia (2002) estimated the performance of the New England market with the competitive benchmark approach. By comparing their results of the New England market to the results for the California and PJM electricity markets using similar approaches, they showed that the New England market had a more favorable performance than the California and the PJM markets from May 1999 to December 1999.

1.3.2 Firm's activity analysis

Empirical analysis of firm bidding strategies follows a similar rationale to the competitive benchmark approach by investigating the issues related to bid markups of firms in electricity markets. Empirical analysis of firms' activity has been performed for several electricity markets.

Wolfram (1998) analyzed the bidding behavior in the England and Wales market for six months of each year between 1992 and 1994. She focused on the relationship between bid markups and the generator's infra-marginal capacity of the two big companies, National Power and PowerGen. She found increasing strategic bidding in the England and Wales market for the test period.

Wolak (2000) presented a model of ex post profit-maximizing bidding behavior in electricity markets. Based on the submitted bids, the elasticity of the ex post residual demand curve faced by each supplier was evaluated at the market clearing price. The inverse of this ex post residual demand elasticity indicates how much bid markup could be reflected in offers. He demonstrated that a firm's ex post profit-maximizing bidding strategy can be constructed by finding the optimal price and quantity pairs for all possible residual demand realizations under certain conditions. He also showed that the assumed ex post profit-maximizing behavior and the firm's marginal cost curve could be used to estimate the forward financial contract position of a supplier (Wolak (2002)). Wolak (2003) measured the unilateral incentives for each of the five largest electricity suppliers in the California to exercise market power during June 1 to September 30 of 1998, 1999 and 2000.

Puller (2001) analyzed the behavior of five generating firms in California from April 1998 to September 1999. He analyzed the market power of firms by measuring bid mark up directly or by the first order condition of static or dynamic Cournot models. In order to minimize the bias from operational constraints, he chose data for one particular hour of each day that has the least operational effects for his analysis. By empirical analysis, he found firms exercise static market power during the test period.

Hortacsu and Puller (2004) analyzed the behaviors of two big firms in ERCOT market by the ex post optimal bid strategy assumption, considering bilateral contracts. In order to avoid the complication posed by congestion, they focus on the un-congested 6:00-7:00pm hour during the weekdays from September 2001 and July 2002. Through their empirical analysis, they found that the behavior of the firm with the highest stakes in the ERCOT market seems to fit the assumed ex-post optimality of observed bid functions. However, firms with smaller stakes in the market deviate from the ex-post optimal behavior.

Corts (1999) mentioned that the parameterized static first-order condition could lead to inconsistent estimates of the conduct parameters if the true underlying process is not identical to the assumptions in the model. It is hard to explicitly estimate firms' behavior, because a firm's bidding strategy is related to many factors, such as bilateral contracts, options, fuel markets, operation limits, and capacity limits. The cost of selling a unit of electricity can be greater than production cost if the firm has an opportunity cost that is greater than its production cost, such as the revenue the firm would get from selling power or reserve capacity in a different location or market, or environmental emission credit limits.

Most of these analyses avoid the complications of operational constraints, such as transmission constraints, by ignoring them or analyzing periods when the constraints are not binding on operation. In contrast, one of the goals of this dissertation is to develop analysis that incorporates the operational constraints.

1.4 EQUILIBRIUM MODELS

Although it is well recognized that no model can precisely predict the outcome in electricity markets, there appears to be an agreement that game theory models are indispensable for gaining insight on market participants' possible behaviors and estimating possible market results of alternative market structures (Smeers (1997), Kahn (1998)).

Game theory, introduced in 1944, analyzes the interactions between rational individuals who are interested in maximizing their profits. Even though all players know the structure of the game and that their opponents are rational, they may not be able to predict fully the outcomes of their decisions. Each player's profit depends not only on its own actions but also on the actions of other players. The actions that are best for one player may depend on actions taken by other players, or will take, and even will not take, based on their current actions.

Nash equilibrium is the most common concept used in game theory models applied in electricity markets (Ramos, Ventosa and River (1998), Moitre (2002)). Nash equilibrium specifies strategies with which competing firms mutually maximize their profits. In equilibrium, each player, if the strategies of all other players are held constant, will not gain a higher profit by choosing a different strategy. It is a mathematical technique for studying the likely result from the simultaneous behavior of many self-interested individuals, and for understanding possible strategies of rational players in deregulated electricity markets.

1.4.1 Strategic interactions in equilibrium model

The principal types of strategic interactions in game theory include: perfect competition, monopoly and oligopoly. For perfect competition, all firms produce homogeneous, perfectly divisible output and face no barriers to entry or exit. Producers and consumers have full information, and no transaction costs incurred. In the absence of scarcity, marginal cost will be the equilibrium price. A firm is a monopoly if it is the only supplier of a product without a close substitute. A monopoly facing a downward-sloping demand curve can set a price above marginal costs to maximize profits. There are two or more players in oligopoly games, which include non-cooperative and cooperative oligopoly. In a non-cooperative oligopoly, a small number of players act independently but are aware of one another's existence. In cooperative oligopolies, a small number of players coordinate their actions to maximize joint profits. Even without an explicit agreement, firms may coordinate their actions to maximize joint profits.

There is an agreement among economists on the modeling of competition and monopoly. There is no such consensus on the modeling of non-cooperative oligopoly interactions. However, most economists agree about the basic characteristics of oligopoly games, which is that players produce homogeneous products and maximize their expected profit. The reason for the lack of agreement in non-cooperative oligopoly model is that a player must consider other players' behavior to decide its best strategies. A monopolist does not need to consider other players, because it is the only player in a market. For perfect competition, each individual competitive player is too small to affect the market price. Therefore, each player could reasonably ignore the actions of other players. In contrast, there are a few players in an oligopoly game. Each player knows that it can affect market price and hence its rivals' profit.

The various oligopoly models differ in their assumptions about the type of actions players may take (such as set prices or set outputs), the order in which they may take actions (such as which firm makes decision first), and the length of the game (one-period model or multi-period model). Three best-known oligopoly models in industry organization are Cournot, Bertrand, and Stackelberg models. Players in the Cournot and Stackelberg models set their output levels, whereas they set prices in Bertrand models. All the players act simultaneously in the Cournot and Bertrand models. In Stackelberg models, one player sets its output level before the others. As the number of players in the market increases, the Cournot and Stackelberg equilibrium become closer to the perfect competitive result. However, the Bertrand equilibrium is unaffected by the number of firms. As long as the market has at least two players with unlimited capacity, the Bertrand equilibrium is the same as the perfect competitive optimum.

In addition to those three oligopoly models, Klemperer and Meyer (1989) developed the Supply Function Equilibrium (SFE) model to analyze profit-maximizing equilibrium in a marketplace with uncertain demand. In SFE models, players decide price and quantity functions (supply functions) simultaneously rather than simply set prices or output quantities as in the above Bertrand, Cournot, and Stackelberg models. The equilibrium price of SFE models lies between the Bertrand and Cournot equilibrium prices.

1.4.2 Applications of equilibrium models

All of the above equilibrium models have been applied to analyze the interactions between competing generating firms in electricity markets. Most models implicitly or explicitly assume a pool electricity market in their studies, where generating firms bid most of their capacity to the market and the Independent System Operator (ISO) dispatches the generators within the system based on their bids to meet the load demand.

A collusion game was presented in a price limiting game (Hobbs (1985)) and a cooperative Nash bargaining game (Bai (1997)). Berry, Hobbs, and Meroney (1999) examined the perfect competition, oligopoly competition, and monopoly competition in a power pool system considering transmission network to analyze the effects of network structure on market result. Hobbs (1985) presented a Bertrand model and showed that price falls to marginal cost if there is no capacity limit and transmission cost. The Stackelberg model was used to analyzing the interactions between large suppliers and the smaller suppliers (Hobbs (2000)). In 2001, Hobbs also presented two Cournot models to analyze bilateral markets. Cunningham, Baldick, and Baughman (2002) formulated a Cournot model to analyze the restructured ERCOT market and showed there is no equilibrium when there is transmission congestion for their equivalent example system. The approaches to mitigate the market power related to Transmission Congestion Rights (TCRs) are discussed with Cournot models in (Olmos and Neuhoff (2004), Gilbert, Neuhoff, and Newberry (2002)).

Although Cournot, Bertrand and Stackelberg models are widely applied to the restructured electricity markets, the appropriateness of the assumptions of these models for electricity markets have been challenged. In electricity markets, every firm offers a price and quantity schedule (supply function), not a price or quantity, for each of its generator or entire output simultaneously to the market operator. The SFE model initiated by Klemperer and Meyer (1989) reflects these price and quantity schedule in their assumption. Market participants submit a price and quantity function (supply or bid function) in the SFE model. At SFE, no player wants to unilaterally change its supply function in order to maximize its profit. The decision variables are the parameters of the supply function, rather than simple quantity or price as in the Cournot, Bertrand and Stackelberg models. Therefore, from the aspect of bid rules of electricity markets, SFE model offer a more realistic view of electricity markets.

In addition to offering a more realistic view of electricity markets, the SFE model has the strength that it depends less on the specification of demand curve than the widely used Cournot models. In Cournot models, the market price is determined by the intersection of the aggregate quantity offered by all market players and their residual demand curve. If the residual demand elasticity is zero, there will be no solution for Cournot models. Therefore, demand elasticity or a competitive fringe is critical and necessary for the solution of Counot modes. However, the short-run demand elasticity in electricity market is almost zero, and it is difficult to specify the market demand curve. As a result, price predictions from Cournot models depend on assumptions about a competitive fringe and are not very reliable. Frame and Joskow (1998) mentioned that they are not aware of any significant empirical support for the Cournot model providing accurate predictions of prices in an electricity market.

In contrast, neither demand elasticity nor a competitive fringe is necessary for the existence of SFE equilibrium. The price and quantity supply functions from players creates elasticity of the residual demand faced by each player. Therefore, the existence of equilibrium in SFE model does not require the system demand to be elastic, and SFE models can deal with the zero demand elasticity case. The price predictions from SFE models are generally sensible, which represents an intermediate level of competition, lying between the Bertrand and Cournot results. In applying SFE models to England and Wales electricity market (Green & Newbery (1992), Baldick, Grand, and Kahn (2004)) shows that SFE models could predict prices that match the empirical data reasonably.

The above merits of SFE models have attracted many researchers to apply them to the analysis of various issues in electricity markets, including the impact of strategic behavior, market divesture, long-term contracts, and impacts of transmission network on electricity prices. Green and Newbery (1992) firstly applied the SFE model to the England and Wales electricity market to investigate how divestiture will affect the market outcome. Their publication attracted a substantial interest to the SFE model both in the industry and in academia. Newbery (1998) and Green (1999) explored the effects of contract market on the equilibrium with SFE models. Rudkevich (1999) presented an SFE model to analyze the ability of players to adapt their behavior through market observations. Bohn, Klevorick, and Stalon (1999) tried to use an SFE model to gain insights into the bidding behavior of firms in the California Power Exchange. Ilic (1998) and Berry, Hobbs and Meroney (1999) examined how the network structure affects the competition with an SFE model. Rudkevich (2002) offered an SFE model to find the effects of different payment rules ranging from the one-price to the pay-as-bid market design. Baldick (2001) examined the interaction of capacity constraints, price caps, and the length of the time horizon over which bids must remain unchanged.

Although the SFE model represents the bid rules of electricity markets more realistically, at the same time this realism also brings difficulty to calculate equilibrium. The challenge to solve SFE models is caused by the non-convexity of the optimization problem faced by each firm. Without restrictive assumptions on the SFE models (which will be discussed in detail in Chapter 4) and powerful algorithms, it is very difficult to find equilibrium. Even though the approach for solving coupled differential equations (Klemperer and Meyer (1989)) has been used successfully by (Green and Newbery (1992)) and (Green (1996)), they always involve symmetric or asymmetric duopoly cases. In markets with asymmetric multiple players and capacity constraints, the differential equation approach may not be effective because the solution typically violates the non-decreasing constraints (Baldick and Hogan (2002)). Even when the differential equation approach yields solutions that satisfy the non-decreasing constraints, many of the equilibriums are unstable (Baldick and Hogan (2002)). Since the asymmetric and multiple player cases are more interesting in practice, an iterative numerical approach (Berry (1999)) was developed.

Normally, the iterative procedure starts by solving the profit-maximizing problem of one player in its feasible supply functions space by arbitrarily fixing the supply functions of other players. After the optimal supply function for the considered player is found, it is fixed and the procedure is repeated for the next player. The process continues until no player wants to change its supply function in order to maximize its profit. There is no guarantee that the iterative approach will converge. However, the applications of this approach showed that it could produce consistent and useful results (Berry, Hobbs (1999), Hobbs, Carolyn and pang (2000), Day (2001), Baldick and Hogan (2002)).

Iterative procedures have also been used to find the equilibrium with transmission constraints. The system ISO market-clearing procedure based on the network model is imbedded in the profit-maximizing problem for each player. Then, electricity market prices depend not only on economic principles, but also on Kirchoff's laws. Borenstein, Bushnell, and Stoft (2000), Cunningham, Baldick, and Baughman (2002), Younes and Ilic (1998), and Oren (1997) showed that transmission constraints could encourage strategic behavior from participants to increase profits, and have important effects on the equilibrium solution in electricity market.

SFE models with transmission constraints provide useful tools to study oligopoly games in the complicated electricity transmission networks. However, the SFE models with transmission constraints are usually computationally challenging. The transmission congestion exacerbates the non-convexity problem of player's optimization problem. Algorithms are usually exposed to the problems of non-existence of equilibrium or multiple equilibriums. Borenstein, Bushnell, and Stoft (2000) and Cunningham, Baldick, and Baughman (2002) showed that transmission constraints could disrupt a pure equilibrium and no pure strategy equilibrium exists for their cases because of congestion. Hobbs, Metzler, and Pang (2000) observed that there are likely to be multiple equilibriums if multiple players can choose intercept and slope arbitrarily.

In order to facilitate the finding of equilibrium, many approaches involve restriction on the parameter of the linear supply function for SFE models with transmission congestion in order to guarantee a unique SFE, (Green (1996)), Berry, Hobbs and Meroney (1999) assumed that player could only manipulate the intercept, or the slope of the linear supply function (Green (1996)). Younes and Ilic(1998), Weber and Overbye (1999) assumed that the slope and the intercept of the linear supply function have a fixed linear relationship.

Baldick (2002) demonstrate that these artificial assumptions in the parameterization of the supply function model have a significant effect on the calculated results for the single pricing-period case. Whether or not pure strategy equilibrium exists can also depend on assumptions about the parameterization of the supply functions. He also mentioned that fixed slope SFE model could be appropriate for a multiple pricing-period market where each player must bid same function for several pricing periods.

To summarize, SFE models have become a good tool to understand how market power could be exercised in the actual electricity market and estimate the possible result from market power. Such an understanding is critical for the development of an efficient market power mitigation procedure. Without an effective market power mitigation procedure, the competition of electricity markets could not be assured because of their vulnerability to market power abuse. In this context, SFE models are valuable for a good electricity market design.

Despite the difficulties faced by SFE models, the empirical applications of SFE models to the England and Wales market (Green, Newbery (1992), Green (1996, 1999), Day (2001), Baldick (2001, 2004)) and the California market (Bohn, Klevorick, and Stalon (1999)) did show their usefulness to understand the mechanisms that market power could be excised and the possible results that market power could bring to the markets.

Since electricity transmission network can have important effects on the equilibrium solution in electricity market, it is important to address the engineering characteristics to the electricity market analysis. There are two approaches to incorporate transmission effects in an approximate manner. One is known as a transportation model, and the other one is DC load flow model. The basic difference between them is whether flow over links of electric transmission system is dependent with each other. The transportation model neglects all electrical characteristics of the transmission network except for capacity limits. This brings a substantial reduction in the computation of the problem, at the cost of being less accurate. The DC model retains reasonable fidelity to electrical properties. DC power flow model has been used in the literatures (Berry (1999), Hobbs (1999), Smeers and Jing-Yuan (1997), Cardell (1997)).

Harvey and Hogan (2002) emphasize that high wholesale electricity prices do not necessarily indicate market power. High cost, increased demand, capacity constraints, and shortages can also be the reasons. They also emphasize the importance of sensitivity analysis in the simulation approach to avoid errors in simulation models. If the sensitivity analysis reveals relatively small changes in the estimated market prices, the errors may not be important.

In the market efficiency analysis models proposed in this dissertation, capacity constraints and transmission constraints are considered. The effects of transmission constraints and operational constraints on market prices based on the actual bids are also analyzed. Transmission network is also incorporated in the SFE bidding strategy simulation model. Sensitivity is discussed in section 4.4.1 for the bidding strategy simulation model proposed. We show that the simulation results are not sensitive to the assumptions for the models.

1.5 IMPORTANCE AND CONTRIBUTIONS

As we discussed above, a perfectly competitive market does not exist in practice. Many issues can contribute to the electricity market inefficiency, such as market design flaws, market power abuse, and inherent engineering features of power system operations. Underlying the growing debates over the appropriate organization of the electricity industry, there is a critical need for the performance evaluation of the electricity markets that are already operating and understanding the behaviors of market participants.

Models for electricity market efficiency and bidding strategy analysis are developed in this dissertation based on competitive benchmark model and supply function equilibrium model representing transmission constraints. Competitive benchmark analysis is an approach to evaluate the performance of electricity markets by estimating how much the actual market prices deviate from the perfect competitive benchmark prices based on actual generation costs or cost estimates. Although perfect competition is rarely encountered in the real world, it provides a benchmark against which to compare various markets having different structures. Since some characteristics of electricity markets facilitate the exercise of market power, market power analysis has received attention in both theory and practice. Game theory has been used to analyze the market power or bidding strategy issues.

For the electricity market efficiency analysis, a competitive benchmark model with transmission and operational constraints is developed in this dissertation to estimate the competitive benchmark prices. Two more models are developed to estimate the effects of transmission and operational constraints on market efficiency based on the submitted bids. The research contributes to the literature in three aspects. First, transmission and operational constraints are considered in the competitive benchmark estimation model, which is neglected in most empirical literature. In reality, transmission and operational constraints affect the competitive benchmark even if the suppliers and buyers truthfully reveal their marginal cost and demand functions. Second, the effects of operational and transmission constraints on market prices are estimated through two models based on the submitted bids of market participants. Third, these models are applied to analyze efficiency of the ERCOT real-time energy market by simulating the market from January 2002 to April 2003, considering the characteristics and available information for the ERCOT market. ERCOT is undertaking a market redesign rulemaking process. Evaluation of the performance of its current market is helpful for this policy process.

For the bidding behavior analysis, a linear asymmetric SFE model with transmission constraints is proposed to analyze the bidding strategies with forward contracts. In electricity markets, electric firms compete through both spot market bidding and bilateral contract trading. Firms have to consider their forward contract positions when they make their spot market decisions. The model contributes to the literature in several aspects. First, we combine forward contracts, transmission constraints and multi-period strategy (an obligation for firms to bid consistently over an extended time horizon such as a day or an hour) into the linear asymmetric SFE framework. As an ex-ante model, it can provide qualitative insights into firms' behaviors. Second, the bidding strategies related to Transmission Congestion Rights (TCRs) are discussed by interpreting TCRs as a linear combination of forwards. Third, the model is a general one in the sense that there is no limitation on the number of firms and scale of the transmission network, which can have asymmetric linear marginal cost structures. In addition to theoretical analysis, we apply our model to simulate the bidding behaviors in the ERCOT real-time balancing energy market from January 2002 to April 2003. Most applications of oligopoly models in electricity markets focus on contract markets or day-ahead pool markets. Our model shows that real-time market analysis is also valuable even when it is relatively small in trading quantity.

The research performed in this dissertation is valuable for the ERCOT market. The ERCOT market differs from the FERC's SMD and from other electricity markets in many aspects. Some of the findings in other restructured markets may not be suitable for the ERCOT market reality. Further more, ERCOT is currently undertaking a market redesign rulemaking process. Understanding the performance of its current market and behaviors of market participants are very important and instructive for this policy process. Because of the short history of the ERCOT market (began on July 31, 2001), not much systematic analysis has been done for this market, compared with the research about the PJM or California market.

As an efficiency analysis of the ERCOT market over time duration of more than one year, this research provides policymakers a vision of the market performance, the effects of operational and transmission constraints on market results, and characteristics of bidding behaviors of market participants. Another potential value of this research is for energy companies. The efficiency analysis enables market participants to know how well the market works. The SFE models enable them to understand the possible behaviors they or their competitors can take and the motivations behind those behaviors. Such understandings are helpful for market participants to make better business decisions within the ERCOT market framework.

Although ERCOT is going to change its market design in the future, the proposed general theoretical framework are applicable to the market analysis with different market structure, including the market structure that the ERCOT market will possibly head to and the transitional period from current market structure to the new market structure. The proposed models can also be extended to study other issues important in electricity markets, such as unit commitment, market power related to transmission congestion (ownership of transmission congestion rights) or operational constraints, relationship between the day-ahead market and the real-time market, and the effects of different contract level on the spot market.

This dissertation is organized as follows. Chapter 2 introduces the history and the market structure of the ERCOT electricity market based on (Baldick and Niu (2004)). The models for competitive benchmark with transmission constraints and the effects of transmission and operational constraints are presented in Chapter 3. The application of these models to analyze the ERCOT real-time market is also performed and discussed in Chapter 3. In Chapter 4, the asymmetric linear SFE model with forward contracts is constructed. The application of this model to the ERCOT real-time energy market is also presented in Chapter 4. The dissertation concludes in Chapter 5 with some suggestions for future research.

CHAPTER 2: THE ERCOT MARKET

2.1 INTRODUCTION

Officially founded in 1970, ERCOT is one of the ten regional reliability councils in North America operating under the reliability and safety standards set by the North American Electric Reliability Council (NERC). Figure 2.1 (Source: www.nerc.com) shows the regions of the ten reliability councils of NERC[2] and shows that the ERCOT system covers most of the geographical area of Texas. As a NERC member, ERCOT's primary responsibility is to facilitate reliable power grid operations in the ERCOT system by working with the region's electric utility industry organizations. The board of directors comprised of market participants with three independent members governs ERCOT.

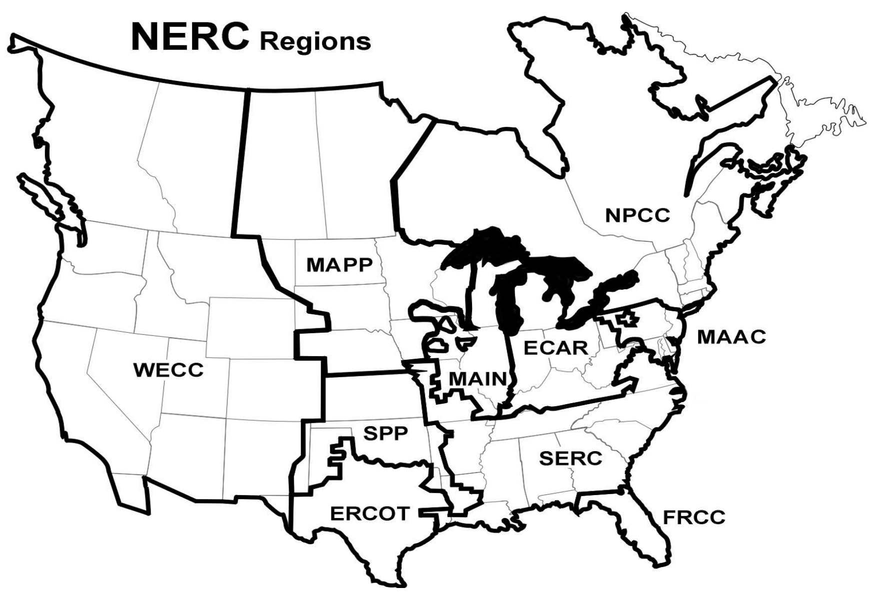

Figure 2.1: Regional Reliability Councils of NERC

[2] The regions are: East Central Area Reliability Coordination Agreement (ECAR), Electric Reliability Council of Texas (ERCOT), Florida Reliability Coordinating Council (FRCC), Mid-Atlantic Area Council (MAAC), Mid-America Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP), Northeast Power Coordinating Council (NPCC), Southeastern Electric Reliability Council (SERC), Southwest Power Pool (SPP) and Western Electricity Coordinating Council (WECC).

Because ERCOT is entirely within the state boundaries of Texas, the production and sale of electricity in ERCOT is not subject to the regulation by FERC, but instead falls exclusively under the jurisdiction of the Public Utility Commission of Texas (PUCT) with laws established by the Texas Legislature. The jurisdictional arrangement for ERCOT is unlike the case in the other lower 47 states where jurisdiction is split between the Federal Energy Regulatory Commission (FERC) and state public utility or public service commissions.

In 1995, the Texas Legislature amended the Public Utility Regulatory Act (PURA) to restructure the wholesale generation market. In 1996, ERCOT was authorized by the PUCT to operate as a not-for-profit Independent System Operator (ISO) to facilitate the efficient use of the electric transmission system by all market participants. In its initial operation, the ERCOT ISO did not fulfill all the functions specified in FERC Order 888 (FERC (1996)). In particular, the ERCOT ISO was not the "control area operator" for ERCOT.

On May 21, 1999, the Texas Legislature passed Senate Bill 7 (SB7) (PUCT, 1999). Under SB7, the ERCOT ISO was given the responsibility to develop the market structure, infrastructure, and business processes to facilitate retail competition in Texas. During 1999 and 2000, the ERCOT ISO and market participants developed "Protocols," which are rules and standards that the ERCOT ISO uses to implement its market functions. The PUCT approved the market rules of the Texas wholesale electricity market (ERCOT protocols) on June 4, 2001 and the ERCOT market began to operate as a single "control area" under the ERCOT ISO on July 31, 2001.

The remainder of this chapter is organized as follows. Section 2.2 is an overview of ERCOT generation resources and market participants. The structure of the ERCOT market is presented in Section 2.3, including the major components of the market, transmission congestion management.

2.2 MARKET OVERVIEW

The ERCOT ISO serves approximately 85 percent of the Texas state's electric load, and oversees the operation of approximately 77,000 megawatts of generation connected by about 37,000 miles of transmission lines over 200,000 square miles area.

2.2.1 Capacity Adequacy

In order to meet reliability criteria, there must be adequate installed capacity. During the eight years between the introduction of wholesale competition to ERCOT in 1995 and early 2003, generation capacity in ERCOT has increased by 30%, while the peak demand increased about 20%. That is, there is currently a large amount of generation capacity relative to demand in ERCOT. Over this period, the installed capacity increased from 59,000 MW to 77,000 MW, while peak demand increased from 46,668 MW to 55,703 MW. (The highest ERCOT peak demand was recorded at 60,059 MW in August 2003).

The "reserve margin" is used to characterize capacity adequacy and is defined as the difference between total electricity generation capacity and peak demand, divided by the peak demand. The ERCOT ISO periodically determines the minimum reserve margin required to ensure the adequacy of installed generation capability. ERCOT utilities have traditionally been required to maintain a reserve margin of 15%.

Based on the NERC report "*Summer Assessment of Reliability of Bulk Electricity Supply in North America*" (NERC (2003)), the summer Available Resources, the Projected Peak Demand, and actual peak demands (ERCOT (2002a)) in ERCOT from 1996 to 2003 are summarized in Table 2.1. "Available Resources" in Table 2.1 are defined to be the existing generation capacity plus new units scheduled for service by the given summer peak month and year, plus the difference between firm capacity purchases and sales, less existing capacity that is unavailable due to planned outages. The projected peak demand is the projected peak-hour demand for the given summer peak month and given year, including standby demand, less the sum of direct control load management (monthly coincident) and interruptible demands. ERCOT predicts a reserve margin of 21.6% in 2004, 18.3% in 2005, and 16.1% in 2006, and 13.6% in 2007.

Table 2.1: Reserve Margins of ERCOT

Year (MW)	1996	1997	1998	1999	2000	2001	2002	2003
Available Resources	56,147	56,446	57,226	57,860	61,751	65,064	75,600	77,563
Projected Peak Load	45,497	46,348	47,808	50,479	52,152	53,391	57,761	57,664
Actual Peak Load	47,683	50,150	53,689	54,849	57,606	55,201	55,703	60,157
Projected Reserve Margin	18.97%	17.89%	16.46%	12.76%	15.54%	17.94%	23.60%	25.66%
Actual Reserve Margin	15.07%	11.15%	6.18%	5.20%	6.71%	15.16%	26.32%	22.44%

2.2.2 Market Participants

SB7 introduced competition to the retail sale of electricity in Texas. Each Investor-owned electric utility (IOU) was required to be unbundled into three distinct kinds of companies: a power generation company (PGC), a transmission and distribution service provider (TDSP), and a retail electric provider (REP). PGCs operate as wholesale providers of generation services. REPs operate as retail providers of electricity. The TDSPs remain regulated by PUCT, and are required to provide non-discriminatory access to the transmission and distribution grid. The PUCT sets the rates for transmission and distribution service.

SB7 allows retail customers of IOUs to select their electricity provider since January 1, 2002. Municipally owned utilities (MOUs) and electric cooperatives (Co-Ops) were granted the option to decide whether and when to open their service areas to retail competition under the so-called opt-in or non-opt-in provision. They are allowed to continue bundled operations regardless of their choice to open their service areas to retail competition.

“Resources” in ERCOT represent entities that are able to meet system demand. A Resource can be a PGC, a Qualifying Facility (QF), a MOU, a Co-Op, an Independent Power Producer (IPP), and a Load Serving Entity (LSE) or a particular load acting as a resource (LaaR). A PGC is the entity registered by the PUCT to generate and sell electricity at wholesale. QFs are a category of cogeneration or small power generating facility that meets certain criteria established by the FERC. IPPs are non-utility power generators that are not regulated utilities, government agencies, nor the certified as QFs. LSEs are entities that provide electric service to customers, which include REPs, Competitive Retailers (CRs), and Non-Opt-In Entities (NOIEs). The plethora of categories of Generation Resources and of LSEs reflects the co-existence of grandfather entities with restructured IOUs and with new entities such as CRs.

The matching between generation resources and LSEs constitutes a "schedule." Market participants are required to submit their schedules of energy to the ERCOT ISO through Qualified Scheduling Entities (QSEs). QSEs are qualified by the ERCOT ISO in accordance with the Protocol to submit schedules and ancillary services bids and settle payments with the ERCOT ISO for the entities in their portfolio. The schedule process will be discussed in detail at Section 2.3.

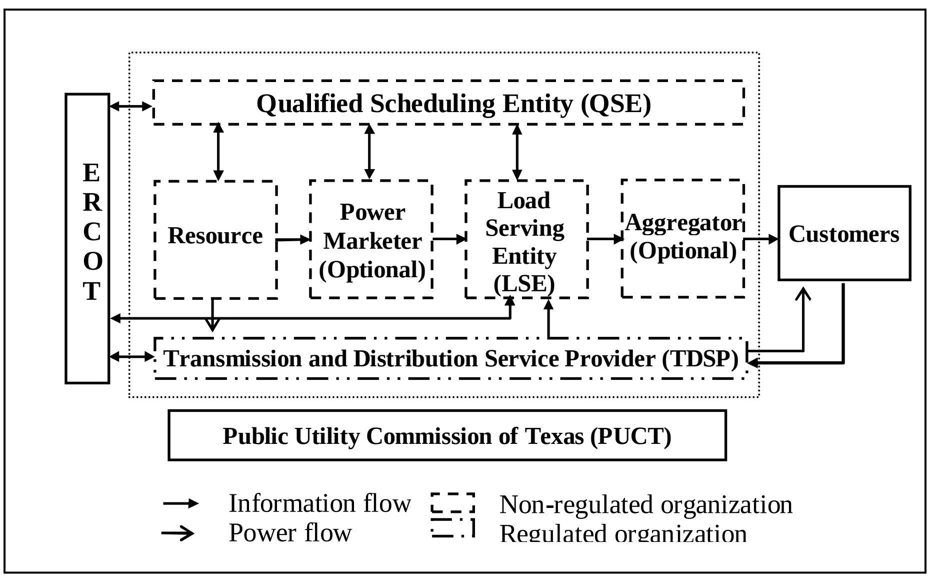

Figure 2.2: Overview of ERCOT Market Participants

As of early 2003, there are 46 QSEs, 52 CRs, 153 aggregators, 16 REPs, 17 power marketers, 37 electric cooperatives, 16 municipally owned utilities, 8 investor-owned utilities, and 5 IPPs (PUCT (2003c), ERCOT (2003b)). Figure 2.2 (Source: ERCOT (2001)) shows the relationship between major market participants in the ERCOT market. In addition to the entities already described above, Figure 2.2 also shows “power marketers” and “aggregators.” A power marketer does not own generation, transmission, or distribution facilities in Texas, and does not have a certified service area, but has been granted to sell electric energy at market-based rates. Aggregators join two or more customers into a single purchasing unit to negotiate the purchase of electricity from retail electric providers.

2.3 MARKET STRUCTURE

The current ERCOT market is different from the FERC’s SMD and from other electricity markets at U.S. in many aspects. Most of other restructured markets have both a day-ahead centrally dispatched energy pool and a real-time energy market. However, the current ERCOT market does not have a day-ahead energy pool market. There is only a real time balancing energy service (BES) market. ERCOT has a day-ahead portfolio energy schedule process. Table 2.2 compares the current ERCOT market with other US electricity markets (Source: PUCT, 2003b).

Table 2.2: Market Structure Comparison

Market	Day-ahead Market	Hour-ahead Market	Real-time Market	Congestion Management	ICAP Market	Price/Bid Cap	AMP
ERCOT	Schedule		√	Zonal/flowgate		√	
California MD02	√	√	√	Nodal	√	√	√
ISO-NE	√		√	Nodal	√	√	
MISO	√		√	Nodal/flowgate	√	√	√
NYISO	√	Schedule	√	Nodal	√	√	√
PJM	√		√	Nodal	√	√	
SMD	√		√	Nodal	√	√	√

Note: ICAP refers to Installed Capacity market when resource owners are paid additional money for offering their capacity. AMP refers to Automated Mitigation Procedure used in some U.S. markets to mitigate offer prices.

In the following subsections, we describe the components of the ERCOT market from the following perspectives: bilateral contract market, balancing energy market, congestion management, transmission congestion rights, and ancillary services market.

2.3.1 Bilateral Contract Market

Electricity markets that have both a day-ahead centrally dispatched energy market and a real-time market include the (now defunct) California PX, California MD02, the England and Wales market prior to March 2001, and the two markets in the Northeastern United States, New York and New England markets. In these markets, bilateral transactions between generation and demand are essentially “financial” in nature that the actual dispatch is decided by the pool rather than specified by the bilateral contracts. The role of bilateral contracts in these markets is to financially hedge against pool price variation.

Unlike the pool markets, the ERCOT wholesale market only has a day-ahead portfolio energy schedule process. The schedules in ERCOT indicate the matching of generation resources with LSEs demand. LSEs forecast their customers’ load and negotiate privately with generation resources or power marketers to buy energy for their customers. Forward contracts between LSEs and generation resources or power marketers are typically incorporated in their schedules.

The schedules represent the about 95% to 97% of delivered energy in the ERCOT. Therefore, bilateral transactions represent the bulk of delivered energy in the ERCOT system. The ERCOT ISO only dispatches the deviation of energy and load from their schedules. Therefore, if a QSE perfectly reflects its actual resources, load, and forward contracts in its schedule, they could minimize their exposure to the BES market by locking in their forward contracts. In contrast to the financial bilateral transactions in pool markets, the bilateral transactions in ERCOT have a “physical” flavor in that, in principle, a bilateral transaction that is scheduled by a QSE is expected to occur.

Market participants in ERCOT are required to submit their schedules to the ERCOT ISO by QSEs. QSEs initially were required to submit a balanced schedule where scheduled generation should equal the scheduled load based on their load forecast. In November 2002, “relaxed balanced scheduling” was implemented on a trial basis, under which QSEs are not anymore expected to schedule demand equal to their load forecast. After an REP bankruptcy due to the high BES prices in February 2003, the allowable deviation between the schedules and load forecast is limited since April 2003 unless additional credit is posted by the QSE in question.

2.3.2 Balancing Energy Market

The current ERCOT market design reflects the philosophy of minimizing the involvement of the ISO (min-ISO) in the electricity market, where the ISO just operates a residual market or a “net pool” (Hogan (1995)). The ERCOT ISO is only involved in the transaction of the imbalances between actual conditions and schedules, and in clearing congestion and taking other actions to maintain system reliability. A balancing market is necessary because energy supply and demand must be balanced continuously since electrical energy cannot be cheaply stored. About 3% to 5% of the total energy is transacted through the balancing energy market operated by the ERCOT ISO.

According to the ERCOT market guide (ERCOT (2001)), the market operations process contains three major periods: day-ahead Ancillary Services (AS) markets, adjustment period, and operating period. The day-ahead AS market occurs from 6:00AM to 6:00PM on the day prior to the operating day. QSEs submit portfolio schedules and ancillary services bids day-ahead. The adjustment period happens between the close of day-ahead AS markets and one hour prior to the operating hour (the current clock hour). QSEs may adjust their schedules, BES bids, and update their resource plans during this period. By the end of the adjustment period, ERCOT receives final bids for balancing energy up (BEU) and balancing energy down (BED). The operating period includes the operating hour and the hour prior to the operating hour.

The ERCOT ISO clears the BES market every 15 minutes based on the hourly BES bids and schedules submitted by QSEs to keep system balance and flows on the inter-zonal constraints within their transmission capacities. BES bids include BEU and BED bids, specified by congestion zone with monotonically increasing ordered pairs of prices and cumulative megawatts ($/MWh, MW). The bid caps are $1,000/MWh for BEU and –$1,000/MWh for BED. As well as the above zonal portfolio level BES bids, QSEs can also voluntarily submit their resource specific premium bids to help solving local reliability issues. Resource specific premiums include price premium at which a resource will increase or decrease its operation level from its current operating point and unit specific dispatchable range.

Settlements of the balancing energy are based on the zonal aggregate load imbalance and resource imbalance for each QSE. The load imbalance is the difference between the scheduled load and actual load from each QSE, while the resource imbalance is the difference between the scheduled generation and actual generation for each QSE. The actual load and generation amounts are derived from the load and resource meter readings.

2.3.3 Congestion Management

If the scheduled power on transmission elements is expected to exceed their transfer capability, called congestion, the ISO has to re-dispatch resources to relieve congestion and balance system at the same time. Prior to June 2004, ERCOT used a two-step zonal congestion management scheme.

The ERCOT ISO categorizes congestion as either inter-zonal congestion or local congestion. The transmission grid, including generation resources and loads, is divided into several congestion zones determined annually. Each congestion zone is defined such that each generation resource or load within the zone is assumed to have a similar effect (characterized by its “shift factor”) on the transmission facilities between congestion zones, called Commercially Significant Constraints (CSCs). The congestion on CSCs or predefined Closely Related Elements (CRE) is called inter-zonal congestion or CSC congestion. The congestion occur on other transmission elements are called local congestion.

ERCOT re-assesses CSCs annually, based on the changes of the system topology. New congestion zones may be identified based on the re-assessed CSCs. In 2001, there were three congestion zones in ERCOT: North Zone, South Zone and West Zone, and two CSCs: transmission from Graham to Parker (West to North) and from Limestone to Watermill (South to North). There were four congestion zones for 2002 and 2003: North Zone, South Zone, West Zone and Houston Zone. The transmission from Sandow to Temple (South to North), Graham to Parker (West to North), STP to DOW (South to Houston), and Parker to Graham (North to West) were the CSCs for

2002. There were only three CSCs in 2003, involving transmission from STP to Dow (South to Houston), from Graham to Parker (West to North) and from Sandow to Temple (South to North). The CSCs and congestion zones of ERCOT in 2003 are shown in Figure 2.3 (Source: ERCOT (2002a)).

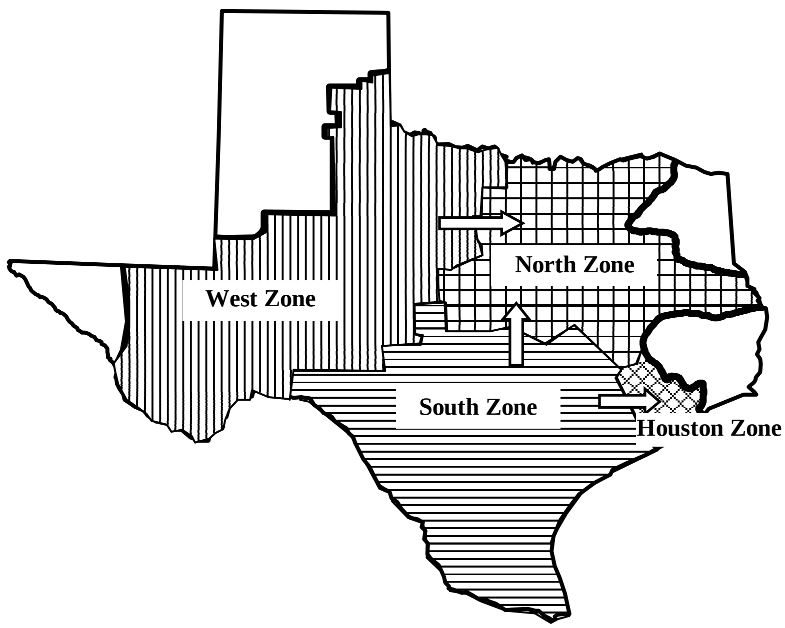

Figure 2.3: CSCs of ERCOT in 2003

In the two-step congestion management process, the ERCOT ISO manages the CSC congestion first. The Market Clearing Price of Energy (MCPE) is determined for each zone based on the zonal portfolio BES bids, and CSC transmission limits. Zonal generation-weighted average shift factors, are used as an approximation to the actual shift factors of each generation unit within the zone to manage congestion on CSCs. Therefore, generators are exposed to locational prices that reflect the average effect of location in zones on CSCs. When only transmission congestion on CSCs needs to be managed within the ERCOT region, only portfolio instructions are issued on a zonal basis. These zonal instructions are settled based on MCPEs.

If there is local congestion, ERCOT ISO relies on a more detailed operational model based on unit-specific bids and shift factors to instruct particular resources to relieve local congestion in the second step. The unit specific deployments are settled based on unit specific bids or out of merit price set by protocols, rather than by MCPEs, The cost of relieving local congestion is uplifted to each QSE based on its Load Ratio Share (LRS)[3].

2.3.4 Transmission Congestion Rights

When ERCOT began operation as a single "control area" on July 31, 2001, inter-zonal congestion re-dispatch costs were uplifted among market participants on a "load ratio share" basis. This presented an opportunity for profiting by over-scheduling and then being paid to relieve congestion, which is similar to the "Inc and Dec" game in the California market. Serious over-scheduling was observed in the first month of single control area operation in August 2001.

The potential for this problem was anticipated (Oren (2001)). The PUCT required ERCOT to switch to a "direct assignment" methodology (that is, charging zonal congestion rents) by January 1, 2003 or six months after inter-zonal re-dispatch costs rose above $20 million on a rolling twelve-month period, whichever came first. It also required ERCOT to implement a system of transmission congestion rights (TCRs), which would allow market participants to hedge their inter-zonal congestion charges.

The $20 million threshold for inter-zonal re-dispatch costs was reached on August 15, 2001, just 15 days after beginning of the operation as a single control area. "Direct assignment" and the TCR system were implemented on February 15, 2002. Under direct assignment, the charge or payment to a QSE is based on the product of its scheduled flow and shadow prices on the congested CSCs. That is, a QSE is exposed to the variation of the shadow price for the CSC.

Figure 2.4 shows the monthly zonal re-dispatch costs (until February 14, 2002) and congestion rent (after February 15, 2002) in ERCOT. Zonal congestion rent after February 15, 2002 was significantly less than the re-dispatch cost prior to February 15, 2002. This strongly suggests that significant over-scheduling was taking place prior to February 15, 2002. Over-scheduling across the CSCs has stopped and should not re-

[3]ERCOT implemented three-step congestion management process in June 2004, which relies on BES

occur because the change to direct assignment of zonal congestion rent removed the incentives for QSEs to over-schedule load across the CSCs.

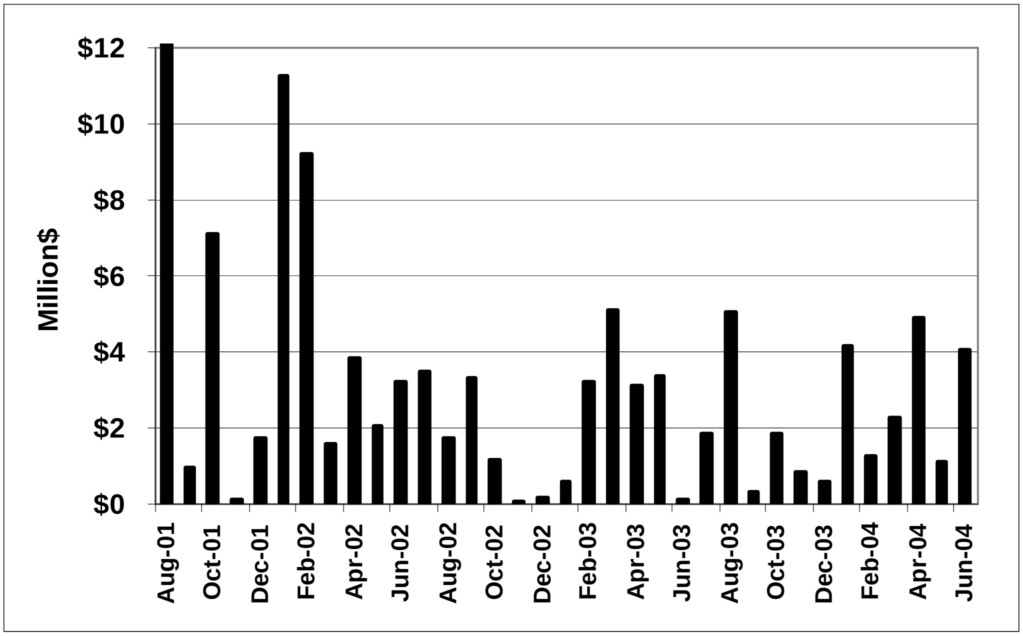

Figure 2.4: CSC Congestion Costs

Transmission Congestion Rights (TCRs) and Pre-assigned Congestion Rights (PCRs) were implemented as financial hedges against the CSC congestion rents. TCRs are awarded in yearly and monthly simultaneous combinatorial auctions based on the auction clearing prices. PCRs are allocated to MOUs and Co-Ops rather than awarded by the TCR auction process and are priced significantly lower than prices charged for TCRs. For all other purposes, PCRs are functionally and financially equivalent to TCRs.

MOUs and Co-Ops that made a long-term (greater than five years) contractual commitment for annual capacity or energy from a specific remote generation resource prior to September 1, 1999, are eligible for PCRs between the zone of their resource and the zone of their demand. PCRs are available on an annual basis until the date upon which an MOU or Co-Op implements retail customer choice, or alternatively, until such other date as may be specified by Order of the PUCT. The cost of PCRs equals fifteen

market rather than OOM services for local congestion.

percent of the applicable annual TCR auction clearing price for each CSC for which a PCR is allocated. PCRs may be traded in the secondary market. Holders of PCRs are not precluded from participating in the market to purchase additional TCRs.

The ERCOT ISO initially conducted a simple, single round TCR auction for each CSC. However, TCRs for various CSCs are closely inter-related products. Having separate markets for them poses difficulties for achieving efficiency. To respond to this issue, the Congestion Management Working Group of the Wholesale Market Subcommittee drafted Protocol Revision Request (PRR) 329 in May 2002 to implement the PUCT order to convert the simple auction to a combinatorial auction of TCRs. This PRR was approved on May 9, 2002, and it became effective on January 1, 2003. By this revision, the ERCOT ISO conduct a single-round, simultaneous combinatorial auction for selling the TCRs available for each annual or monthly auction for all CSCs. In this auction, bidders can reflect their needs for TCRs on multiple CSCs simultaneously. The clearing-price for each TCR equals to the corresponding shadow price of the marginal TCR awarded on that CSC.

Under some circumstances, PCRs and TCRs have the potential to enhance market power (Oren (1997), Joskow (2000)). As an *ad hoc* approach to mitigating market power in ERCOT, no entity combined with its affiliates may, directly or indirectly, own, control, or receive the revenue from more than 25% of the total available TCRs at a particular CSC interface for any single direction and a given hour.

2.3.5 Local Congestion

A similar situation currently exists for local congestion as existed for zonal congestion prior to February 15, 2002. In order to mitigate local market power, the ERCOT protocols define a “market solution” for local congestion as when at least three unaffiliated resources, with capacity available, submit bids to the ERCOT ISO that can solve the local congestion and no one bidder is essential to solving the congestion. If there is no market solution, bid prices are mitigated based on verifiable operating costs.

There has been no “market solution” for local congestion in ERCOT in most cases prior to June 2003. That is, local market power is deemed to exist most of the time when local transmission constraints are binding. Instead of relying on a market process to determine prices, ERCOT obtains commitments to provide capacity and energy at a pre-specified cost level. These are called Out of Merit Order Energy (OOME) and Out of Merit Order Capacity (OOMC). OOME services are provided by resources selected by ERCOT ISO outside the bidding process in order to resolve local congestion when no market solution exists. OOMC provides generation capacity needed such that balancing energy is available to solve local congestion or other reliability needs when a market solution does not exist. OOMC can be provided from any resource or load acting as a resource that is listed as available in the resource plan.

Sometimes a Reliability Must Run (RMR) unit may be needed to provide generation capacity or energy resources when there is no market solution. A RMR unit is a generation resource unit operated under the terms of an annual agreement with ERCOT that would not otherwise be operated usually except that they are necessary to provide voltage support, stability, or management of localized transmission constraints under first contingency criteria where Market Solutions do not exist.

The local congestion cost is uplifted to each QSE based on the load ratio share of the QSE. Figure 2.5 shows the local re-dispatch costs in ERCOT from August 2001 to June 2004. In Docket No. 23220, *Petition Of The Electric Reliability Council Of Texas (ERCOT) For Approval Of The ERCOT Protocols*, the PUCT ordered the ERCOT ISO to implement direct assignment of local congestion costs if the re-dispatch costs for resolving local congestion rose above $20 million in a rolling twelve-month period. The direct assignment of local congestion cost tries to eliminate opportunities for market participants to profit from scheduling that result in congestion on local transmission lines and to send appropriate signals to locate new generation facilities in places that have sufficient transmission capacity to deliver the power to electric consumers. The $20 million threshold for local re-dispatch costs was met on March 5, 2002, after seven months of operation as a single control area. Several proposals have been suggested for solving the local congestion problem, including implementing nodal locational marginal pricing (LMP). ERCOT is currently implementing a Texas Nodal Market design process scheduled for full implementation by October 1, 2006.

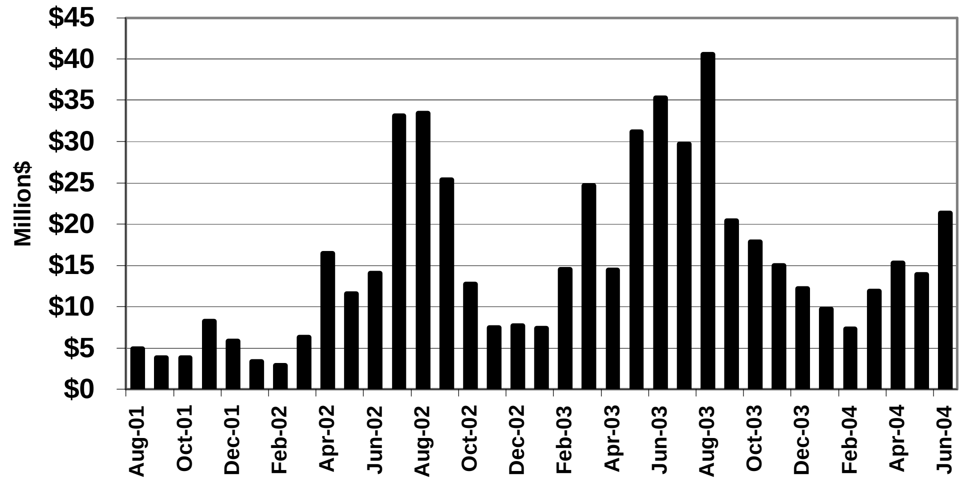

Figure 2.5: Local Congestion Costs

2.3.6 Day-ahead Ancillary Service Markets

Ancillary services (AS) are the services necessary to maintain electric system reliability and security. In ERCOT, each market participant is assigned an obligation to provide ancillary services based on its historical load. Market participants may provide the ancillary services themselves or rely on the ERCOT to acquire the ancillary services through a centralized auction. From August 2001 to December 2002, market participants self-procured between 80% and 90% of their AS obligations.

ERCOT operates a day-ahead AS market for: Regulation Down Services (RgDn), Regulation Up Services (RgUp), Responsive Reserves Services (RRS), Non-Spinning Reserve Services (NSRS), and Replacement Reserve Services (RPRS) as needed. These ancillary services are procured day-ahead for each hour of the following day[4].

We will focus on the ERCOT real-time balancing energy market for the applications of models proposed in this dissertation, while other ancillary services cleared in the day-ahead ancillary services markets will not be considered.

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[4] Normally the required amount of AS services in ERCOT day-ahead ancillary service markets are: 1200-1800 MW for RegDn, 1200 MW for RegUp, 2300 MW for RRS, 1250 MW for NSRS if needed, as well as some RPRS if such services is needed.

CHAPTER 3: MARKET EFFICIENCY ANALYSIS MODELS

3.1 INTRODUCTION

In 2001, The Federal Energy Regulatory Commission (FERC) proposed Standard Market Design (SMD) to unify the best practices in market design, and to enhance competition in electricity markets under its jurisdiction. Currently every U.S. electricity market is seeking ways to improve its market design based on its regional realities.

The evaluation of the electricity market efficiency can help to identify necessary revisions to current markets. Competitive benchmark analysis is an approach to evaluate the performance of electricity markets by estimating how much the actual market prices deviate from the perfect competitive benchmark prices based on actual generation costs or cost estimates. Although perfect competition is rarely encountered in the real world, it provides a benchmark against which to compare various markets having different structures. The competitive benchmark approach has been employed in the studies of several electricity markets, including the England and Wales market, the California market, the PJM market, and the New England market.

Although the competitive benchmark approach can evaluate market performance, it cannot provide the reasons for the market inefficiency. Many issues can contribute to the electricity market inefficiency, such as market design flaws, abuse of market power, and inherent engineering features of power system operations. Optimal bidding strategies theory has been used to analyze the market power issues, which will be discussed in Chapter 4. This chapter focuses on the effects of transmission and operational constraints on market efficiency. Models are developed to estimate the competitive benchmark with transmission and operational constraints and how transmission and operational constraints affect market prices based on the submitted bids.

The proposed models in this chapter contribute to the literature in three aspects. First, transmission and operational constraints are considered in the competitive benchmark estimation model, which is neglected in most empirical literature. In reality, transmission and operational constraints affect the competitive benchmark even if the suppliers and buyers truthfully reveal their marginal cost and demand functions. Second, the effects of operational and transmission constraints on market prices are estimated through two models based on the submitted bids of market participants. Third, these models are applied to analyze the efficiency of the ERCOT real-time energy market by simulating the market from January 2002 to April 2003, considering the characteristics and available information for the ERCOT market. ERCOT is undertaking a market redesign rulemaking process. Evaluating the performance of the current market is helpful for this policy process.

Unlike SMD and other electricity markets in the United States that they have both a day-ahead pool market and a real-time market, the current ERCOT electricity market does not have a bid-based day-ahead energy market. There is only a real-time balancing energy market (BEM). ERCOT has a day-ahead portfolio energy scheduling process and a day-ahead ancillary services market. We will only focus on the real-time balancing energy market in this dissertation, while other ancillary services will not be discussed.

This chapter is arranged as follows. Section 3.2 describes the proposed models. Section 3.3 presents the simulation results of the competitive benchmark model for the ERCOT real-time BES market using estimates of actual generation costs. Section 3.4 provides simulation results of the models for quantifying the effects of transmission and operational constraint on the market performance based on the submitted bids in the ERCOT market. Section 3.5 concludes this chapter.

3.2 MODEL FORMULATION

A perfect competitive benchmark model has the following major assumptions:

- All firms are assumed to produce homogeneous, divisible output;
- No entry or exit barrier;
- Consumers have full information;
- Total supply exceeds total demand;

- No transaction costs;
- Each firm is competitive or acts as price-taker.

Under these assumptions, a firm will produce electricity and sell at its marginal cost as long as the marginal cost is less or equal to market price. For the whole market, the marginal cost can be defined as the incremental cost to supply the next MW energy demand of the system.

However, transmission constraints and operational constraints affect the competitive benchmark even if the suppliers and buyers truthfully reveal their marginal cost and demand functions. In order to consider these constraints in our market efficiency analysis models, we use a DC power flow model to represent the power system transmission network.

3.2.1 Power Flow Model

Though the electricity industry restructuring is aimed to replace regulation with the forces of market competition, the operation of power systems has to obey the Kirchhopf's laws. The balance between supply and demand has to be maintained all the time for the requirements of the system reliability and power quality. For the same reason, power flows though transmission lines have to be within the transfer capacities of the transmission lines.

Power flow studies are the basis to determine the best operation of electric power systems. From the power flow studies, we can obtain the principle information for system operation including the magnitude and phase angle of the voltage at each bus, and the real and reactive power flowing through each line.

In this section, we examine the Newton-Raphson power flow model, the decoupled power flow model, and the DC power flow model based on Niu and Guo (1998) and Grainger and Stevenson (1994).

1) The Neton-Raphson power flow model

It is assumed that there are n nodes in the system. The bus admittances of the electric power system is $\mathbf{Y}$, which is composed of the bus self- and mutual admittances. Nodal current, nodal voltage, and nodal complex power are denoted by vectors $\mathbf{I}$,

$\mathbf{V}$ and $\mathbf{S}$, respectively. The phase expressions for voltage, current and complex power can be written as:

$$\mathbf{S} = \mathbf{P} + j\mathbf{Q}, \tag{3.1}$$

$$\mathbf{V} = \mathbf{e} + j\mathbf{f}, \tag{3.2}$$

$$\mathbf{Y} = \mathbf{G} + j\mathbf{B}. \tag{3.3}$$

In power systems, nodal current and nodal voltage satisfy:

$$\mathbf{I} = \mathbf{YV}. \tag{3.4}$$

The complex power can be expressed as:

$$\hat{\mathbf{S}} = \hat{\mathbf{V}}\mathbf{I}, \tag{3.5}$$

where $\hat{\mathbf{S}}$ and $\hat{\mathbf{V}}$ are the conjugate vectors of $\mathbf{S}$ and $\mathbf{V}$, respectively.

From (3.4) and (3.5), we have:

$$\frac{\hat{\mathbf{S}}}{\hat{\mathbf{V}}} = \mathbf{YV}. \tag{3.6}$$

Differentiating (3.6) with respect $\mathbf{V}$ gives:

$$\frac{\Delta\hat{\mathbf{S}}}{\hat{\mathbf{V}}} - \frac{\hat{\mathbf{S}}}{\hat{\mathbf{V}}^2}\Delta\hat{\mathbf{V}} = \mathbf{Y}\Delta\mathbf{V}. \tag{3.7}$$

From (3.1)-(3.3), for each node we have:

$$\frac{\hat{S}}{\hat{V}^2} = \frac{P - jQ}{\left(e^2 - f^2\right) - j2ef} = \frac{\left[P\left(e^2 - f^2\right) + 2efQ\right]}{\left(e^2 + f^2\right)^2} + j\frac{\left[-Q\left(e^2 - f^2\right) + 2efP\right]}{\left(e^2 + f^2\right)^2}. \tag{3.8}$$

Then for each node, (3.7) can be rearranged as:

$$\frac{\Delta\hat{S}}{\hat{V}} = \begin{bmatrix} G & -B \\ B & G \end{bmatrix}\begin{bmatrix} \Delta e \\ \Delta f \end{bmatrix} + \begin{bmatrix} D_{11} & D_{12} \\ D_{21} & D_{22} \end{bmatrix}\begin{bmatrix} \Delta e \\ \Delta f \end{bmatrix} \tag{3.9}$$

where $\mathbf{D} = \begin{bmatrix} D_{11} & D_{12} \\ D_{21} & D_{22} \end{bmatrix}$.

From (3.8), we find that $\mathbf{D}$ is a diagonal matrix, where $D_{ij} = 0(i \neq j)$, and

$$D_{ii} = \begin{bmatrix} b & a \\ a & -b \end{bmatrix}, \tag{3.10}$$

where:

$$\begin{cases} a = \dfrac{\left[-Q\left(e^2 - f^2\right) + 2efP\right]}{\left(e^2 + f^2\right)^2} \\ b = \dfrac{\left[P\left(e^2 - f^2\right) + 2efQ\right]}{\left(e^2 + f^2\right)^2} \end{cases}. \tag{3.11}$$

Assume $\Delta\mathbf{I}' = \dfrac{\Delta\hat{\mathbf{S}}}{\hat{\mathbf{V}}}$, equation (3.7) becomes:

$$\Delta\mathbf{I}' = (\mathbf{Y} + \mathbf{D})\Delta\mathbf{V} = \mathbf{J}\Delta\mathbf{V}. \tag{3.12}$$

where $\mathbf{J}$ is a matrix that is similar to the Jacobian matrix for the load flow problem.

Equation (3.12) is the correction equation for solving the nonlinear system equation of (3.4) iteratively, which can be expressed as:

$$\begin{bmatrix} \Delta I'_{x1} \\ \Delta I'_{y1} \\ \Delta I'_{x2} \\ \Delta I'_{y2} \\ \vdots \\ \Delta I'_{xn} \\ \Delta I'_{yn} \end{bmatrix} = \begin{bmatrix} G_{11}+b_1 & -B_{11}+a_1 & G_{12} & -B_{12} & \cdots & G_{1n} & -B_{1n} \\ B_{11}+a_1 & G_{11}-b_1 & B_{12} & G_{12} & \cdots & B_{1n} & G_{1n} \\ G_{21} & -B_{21} & G_{22}+b_2 & -B_{22}+a_2 & \cdots & G_{2n} & -B_{2n} \\ B_{21} & G_{21} & B_{22}+a_2 & G_{22}-b_2 & \cdots & B_{2n} & G_{2n} \\ \vdots & \vdots & \vdots & \vdots & \vdots & \vdots & \vdots \\ G_{n1} & -B_{n1} & G_{n2} & -B_{n2} & \cdots & G_{nn}+b_n & -B_{nn}+a_n \\ B_{n1} & G_{n1} & B_{n2} & G_{n2} & \cdots & B_{nn}+a_n & G_{nn}-b_n \end{bmatrix} \begin{bmatrix} \Delta e_1 \\ \Delta f_1 \\ \Delta e_2 \\ \Delta f_2 \\ \vdots \\ \Delta e_n \\ \Delta f_n \end{bmatrix}. \tag{3.13}$$

The above formulation is for the nodes whose nodal real power P_{is} and reactive power Q_{is} are known. For a voltage-controlled bus, its voltage magnitude V_{is} is kept constant and its nodal real power P_{is} is known. Then the power flow equations for voltage-controlled buses are:

$$\Delta P_i = P_{is} - P_i = P_{is} - e_i \sum_{i=1}^{n} (G_{ij} e_j - B_{ij} f_j) - f_i \sum_{i=1}^{n} (G_{ij} f_j + B_{ij} e_j) = 0, \tag{3.14}$$

$$\Delta V_i^2 = V_{is}^2 - (e_i^2 + f_i^2) = 0. \tag{3.15}$$

The elements of the matrix $\mathbf{J}$ for the voltage-controlled buses can be obtained as we did for equation (3.13). For the off-diagonal elements, where $i \neq j$:

$$\begin{cases} \dfrac{\partial \Delta P_i}{\partial e_j} = -\dfrac{\partial \Delta Q_i}{\partial e_j} = -\left(G_{ij} e_i + B_{ij} f_i\right) \\ \dfrac{\partial \Delta P_i}{\partial f_j} = -\dfrac{\partial \Delta Q_i}{\partial e_j} = B_{ij} e_i - G_{ij} f_i \\ \dfrac{\partial \Delta V_i^2}{\partial e_j} = -\dfrac{\partial \Delta V_i^2}{\partial f_j} = 0 \end{cases}, \tag{3.16}$$

For the diagonal elements, where $i = j$:

$$\begin{cases} \dfrac{\partial \Delta P_i}{\partial e_i} = -\sum\limits_{j \in i} \left(G_{ij} e_j - B_{ij} f_j\right) - G_{ii} e_i - B_{ii} f_i \\ \dfrac{\partial \Delta P_i}{\partial f_i} = -\sum\limits_{j \in i} \left(G_{ij} f_j - B_{ij} e_j\right) - G_{ii} f_i + B_{ii} e_i \\ \dfrac{\partial \Delta V_i^2}{\partial e_i} = -2 e_i \\ \dfrac{\partial \Delta V_i^2}{\partial f_i} = -2 f_i \end{cases}. \tag{3.17}$$

From (3.13), (3.14), (3.16) and (3.17), we update the elements of matrix $\mathbf{J}$ for each iteration, and get the corrections for the state variables Δe_i and Δf_i. The iterative equations for the values of the state variables of voltages are:

$$e_i^{(k+1)} = e_i^k + \Delta e_i^k, \tag{3.18}$$

$$f_i^{(k+1)} = f_i^k + f_i^k. \tag{3.19}$$

The iterations terminate until max{ $\Delta I_{xi}, \Delta I_{yi}, \Delta P_i, \Delta V_i$ } < ε, where ε is the allowable power mismatches and voltage tolerances at the buses.

2) The decoupled power flow model

In practice, the Jocobian is updated only for every a few iterations in order to speed up the overall solution process. For large-scale power transmission systems, decoupled power-flow method is a way to improving computational efficiency.

The decoupled power-flow method is an approximate version of the Newton-Raphson procedure, which simplifies the power-flow model with some characteristics of high voltage power system. These characteristics include that real power in the transmission lines is affected primarily by the change in the voltage angle, and the flow of reactive power in the transmission lines is affected primarily by the change in the voltage magnitude. The physics of transmission-line are also used to simplify the model further:

- Since the angular differences ($\theta_i - \theta_j$) between typical buses of a well-designed and properly operated power transmission system are small, it is assumed that $\cos(\theta_i - \theta_j) = 1$ and $\sin(\theta_i - \theta_j) \approx \theta_i - \theta_j$.
- Since line susceptances B_{ij} are much larger than the line conductances G_{ij}, it is assumed that $G_{ij}\sin(\theta_i - \theta_j) << B_{ij}\cos(\theta_i - \theta_j)$.
- The reactive power injected into any bus of the system during normal operation is assumed much less than the reactive power that would flow if all lines from that bus were short-circuited to reference. That is,
  $Q_i << |V_i|^2 B_{ii}$

If we assume the nodal real power and reactive are known for the first $(n-m)$ nodes and other nodes are voltage-control buses, the Newton- Raphson method can be simplified to the decoupled Power-flow method based on the above conditions:

$$\begin{bmatrix} \frac{\Delta P_1}{V_1} \\ \frac{\Delta P_2}{V_2} \\ \vdots \\ \frac{\Delta P_n}{V_n} \end{bmatrix} = -\begin{bmatrix} B_{11} & B_{12} & \cdots & B_{1n} \\ B_{21} & B_{22} & \cdots & B_{2n} \\ \vdots & \vdots & & \vdots \\ B_{n1} & B_{n2} & \cdots & B_{nn} \end{bmatrix} \begin{bmatrix} V_1\Delta\theta_1 \\ V_2\Delta\theta_2 \\ \vdots \\ V_n\Delta\theta_n \end{bmatrix}, \tag{3.20}$$

$$\begin{bmatrix} \frac{\Delta Q_1}{V_1} \\ \frac{\Delta Q_2}{V_2} \\ \vdots \\ \frac{\Delta Q_m}{V_m} \end{bmatrix} = -\begin{bmatrix} B_{11} & B_{12} & \cdots & B_{1m} \\ B_{21} & B_{22} & \cdots & B_{2m} \\ \vdots & \vdots & & \vdots \\ B_{m1} & B_{m2} & \cdots & B_{mm} \end{bmatrix} \begin{bmatrix} \Delta V_1 \\ \Delta V_2 \\ \vdots \\ \Delta V_m \end{bmatrix}. \tag{3.21}$$

Through these simplifications, real power and reactive power are decoupled separately, and the Jacobian is constant for each iteration. Since the Jocobian is generally symmetrical and sparse, once it is computed at the beginning of the solution process, it does not need to be recomputed. This reduces the computation load and leads to fast iterations.

3) DC power flow model

When approximate power flow solutions are acceptable, the decoupled power flow can be simplified further based on the following assumptions:

- Neglect elements that mainly affect reactive flows: capacitors and reactors;
- The taps of off-norminal transformers are assumed to be 1;
- Neglect series resistances in the equivalent-π circuits of the transmission lines;
- Bus voltage angular differences are small;
- Bus voltage magnitudes are approximately 1.0pu.

With the above assumptions, the electric power transmission losses are ignored and the power system becomes a lossless network. In addition, (3.21) is not necessary because the magnitudes of bus voltage are assumed known. Then (3.20) is called DC power flow model.

Since transmission constraints affect the competitive benchmark even if the suppliers and buyers truthfully reveal their marginal cost and demand functions, we consider theses constraints in our market efficiency analysis models through the DC power flow model to represent the power system transmission system. The major reasons for our choice of DC power flow model include: currently only real power is traded through electricity market; DC power flow model are used in the market-clearing engine for most electricity markets around the world.

In order to incorporate transmission limits into our competitive benchmark model, we adjust the DC power flow model by replacing the nodal real power with the net of nodal injection and load. It is assume that there are n nodes and K transmission lines in the system. The transmission capacity limit vector of the K transmission lines is $\mathbf{FL}_{\max} = [FL_{1\max}, FL_{2\max} \cdots FL_{k\max}]^T$. The voltage angles for other nodes are represented by vector $\boldsymbol{\theta} = [\theta_1, \theta_2 \cdots \theta_n]^T$. The nodal injections, capacity limits, and loads are represented by vectors $\mathbf{q} = [q_1, q_2 \cdots q_n]^T$, $\mathbf{q}_{\max} = [q_{1\max}, q_{2\max} \cdots q_{n\max}]^T$, and

$\mathbf{D} = [D_1, D_2 \cdots D_n]^T$, where q_i refers to the generation at bus i and D_i refers to the load at bus i.

$$D_i = N_i(t) - \gamma_i p_i \tag{3.22}$$

From (3.20), the DC power flow is:

$$\mathbf{B\theta} = \mathbf{q} - \mathbf{D}, \tag{3.23}$$

where $\mathbf{B}$ is the imaginary part of the system nodal admittance matrix. The real power flow on branch between node i and node j is:

$$F_{ij} = b_{ij}\left(\theta_i - \theta_j\right), \tag{3.24}$$

where b_{ij} is absolute value of the branch susceptance between nodes *i* and *j*. Therefore, transmission capacity constraints are:

$$\mathbf{H\theta} \le \mathbf{FL}_{\max}, \tag{3.25}$$

where $\mathbf{H}$ is the product of the branch susceptance diagonal matrix and an appropriate incidence matrix of branches with nodes. If the k th transmission line connects node i and node j, then we have

$$h_{ki} = b_{ij}, h_{kj} = -b_{ij}, h_{kl} = 0, \forall l \in n, l \ne i, l \ne j \,.$$

Substituting (3.23) into (3.25), we have:

$$\mathbf{HB}^{-1}(\mathbf{q} - \mathbf{D}) \le \mathbf{FL}_{\max}\,. \tag{3.26}$$

Define matrix $\mathbf{S} = \mathbf{HB}^{-1}$, whose elements indicating the sensitivity of branch flows to nodal net injections, which are called shift factors. Then the DC power flow and transmission capacity constraints are:

$$\mathbf{S}(\mathbf{q} - \mathbf{D}) \le \mathbf{FL}_{\max}\,. \tag{3.27}$$

From (3.27), we observe that the transmission network is indicated in matrix $\mathbf{S}$.

3.2.2 Competitive Benchmark Model with Transmission and Operational Constraints

Using an optimal power flow (OPF) program, the marginal cost for different demand levels can be estimated through the following optimization problem considering transmission and operational constraints. The transmission network is incorporated into the competitive benchmark model by the DC load flow model.

$$Min \qquad \sum_{i=1}^{n} C_i(q_i) - \sum_{i=1}^{n} B_i(D_i) \tag{3.28}$$

$$s.t. \qquad \sum_{i=1}^{n} (q_i - d_i) = 0, \tag{3.29}$$

$$\mathbf{0} \le \mathbf{q} \le \mathbf{q}_{\max}, \tag{3.30}$$

$$\mathbf{S(q-D)} \le \mathbf{FL}_{\max}, \tag{3.31}$$

$$\Delta\mathbf{q}_{2\max} \le \Delta\mathbf{q} \le \Delta\mathbf{q}_{1\max}. \tag{3.32}$$

The objective is to minimize the total system production cost based on the production cost of each unit or negative benefits of each consumer. $C_i(q_i)$ and $B_i(D_i)$ are the convex production cost and concave consumer benefit function for generator and load at node *i*. Constraint (3.29) represents the system supply and demand balance. Constraint (3.30) represents generation capacity limits. The transmission capacity constraints are specified by (3.31), where matrix $\mathbf{S}$ is the sensitivity of branch flows to nodal net injections, or shift factors. The operational constraints (ramp rate constraints) are represented by (3.32). Vectors $\Delta\mathbf{q}_{1\max}$ and $\Delta\mathbf{q}_{2\max}$ represent the adjustable up and down range of generator output, which depends on its up and down ramp rates, where $\Delta\mathbf{q}_t = \mathbf{q}_t - \mathbf{q}_{t-1}$ is the change in generation from time *t*-1 to time *t*. Ramp rates are the principal operational constraints considered in this dissertation.

The Lagrangian for the optimal problem is:

$$\begin{aligned} L = &\sum_{i=1}^{n} C_i(q_i) - \sum_{i=1}^{n} B_i(D_i) + \lambda(\sum_{i=1}^{n}(D_i - q_i) + \boldsymbol{\mu}^T \mathbf{(S(q-D) - FL_{max})} \\ &+ \boldsymbol{\omega}_1 (\mathbf{q} - \mathbf{q}_{\max}) + \boldsymbol{\omega}_2 (\Delta\mathbf{q} - \Delta\mathbf{q}_{\max}) \end{aligned}, \tag{3.33}$$

where λ, $\boldsymbol{\mu}$, $\boldsymbol{\omega}_1$, $\boldsymbol{\omega}_2$, and $\boldsymbol{\omega}_3$ are multiplier vectors for the constraints of system balance, transmission, generator capacity, and ramp rate constraints.

Since the problem is convex, we can find the optimal solution, denoted as $z^* = [q^{*T}, \lambda^*, \mu^*, \omega^*]^T$, by solving the first order necessary conditions. Because the nodal marginal cost is defined as the incremental cost for providing next unit of nodal demand, the nodal Marginal Cost (MC) can be obtained from $\mathbf{z}^*$:

$$\theta_i = \frac{\partial L}{\partial D_i} = \lambda - \sum_{k=1}^{K} \mu_k s_{ki} , \tag{3.34}$$

where s_{ki} is the element (k , i) of matrix $\mathbf{S}$. The difference between the actual market prices and the marginal costs indicates the price mark-up.

3.2.3 Market Clearing Mechanism

The Independent System Operator (ISO) clears the electricity market based on bids submitted from market participants, instead of their costs. The objective of market clearing is to minimize the total system cost based on the bid prices. Therefore, the market clearing mechanism can be described as the above competitive benchmark model, except that we replace cost and benefit functions with supply and demand bids:

$$Min \qquad \sum_{i=1}^{n} \int_0^{q_i} f_i^s(q)dq - \sum_{i=1}^{n} \int_0^{D_i} f_i^d(D)dD \tag{3.35}$$

$$s.t. \qquad \sum_{i=1}^{n} (q_i - d_i) = 0 , \tag{3.36}$$

$$\mathbf{0} \le \mathbf{q} \le \mathbf{q}_{\max} , \tag{3.37}$$

$$\mathbf{S(q - D)} \le \mathbf{FL}_{\max} , \tag{3.38}$$

$$\Delta \mathbf{q}_{2\max} \le \Delta \mathbf{q} \le \Delta \mathbf{q}_{1\max} , \tag{3.39}$$

where $f_i^s(q_i)$ and $f_i^d(q_i)$ represents supply and demand bids submitted to the system operator. Along with the constraints from (3.29)-(3.33), this model gives the market clearing model. In order to refer to the market clearing model in a later section, we number the constraints in market clearing model separately from the competitive benchmark model. System balance constraint is (3.36). Equation (3.37) represents the generation capacity limits. Equation (3.38) represents the transmission constraints, and (3.39) represents operational constraints. Similar to (3.34), based on the optimal solution, the nodal market clearing price is:

$$p_i = \lambda^* - \sum_{k=1}^{K} \mu_k^* s_{ki} \ . \tag{3.40}$$

Binding operational and transmission constraints affect market price through changes in the optimal value of λ and $\boldsymbol{\mu}$. Constraints may force the ISO to skip some cheaper bids and deploy some more expensive bids. For example, even though cheap units are on line, they may not be dispatchable because ramp rate constraints limit their ability to deviate from their previous generation levels.

In order to analyze the effects of transmission and operational constraints on market prices, we form a Non-Constrained Model (NCM) and a Transmission-Constrained Model (TCM) based on actual market bids. NCM estimates the market price without considering either transmission or operational constraints by relaxing (3.38) and (3.39) in the market clearing model based on the submitted bids. TCM estimates the market price considering transmission constraints, but the operational constraint (3.39) is still ignored.

For the transmission un-congested case, the difference between NCM prices and actual market prices indicates the effects of operational constraints on market results based on the submitted bids. For the transmission-congested case, this difference reflects the effects of both transmission and operational constraints. The price difference between the NCM and the TCM reflects how transmission congestion affects the market result based on the submitted bids. The difference between the TCM prices and actual market prices indicates the effect of operational constraints on market prices based on the submitted bids. The correlation between transmission and operational constraints is not considered here because the operational constraint information is not publicly available.

3.3 APPLICATION OF COMPETITIVE BENCHMARK MODEL

A competitive benchmark model with CSC transmission constraints is developed for the ERCOT market from January 2002 to April 2003 in this section. Since there is no public information about operational constraints, we only consider CSC transmission constraints in the ERCOT competitive benchmark model, which could result in underestimated marginal cost. Actual prices for the ERCOT BEM are compared with the simulated competitive benchmark prices to estimate the market performance. The information related to the software for the applications of these models is provided in the appendix.

3.3.1 ERCOT Model Formulation

There were four congestion zones for both 2002 and 2003 in ERCOT: North Zone, South Zone, West Zone and Houston Zone. Figure 3.1 shows the four congestion zones in ERCOT.

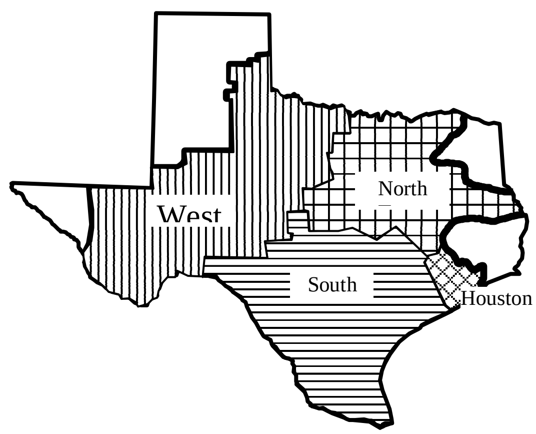

Figure 3.1: ERCOT Congestion Zones 2002 & 2003

The transmission from Sandow to Temple (South to North), Graham to Parker (West to North), STP to DOW (South to Houston), and Parker to Graham (North to West) were the four CSCs for 2002. There are only three CSCs in 2003, involving transmission from STP to Dow (South to Houston), from Graham to Parker (West to North) and from Sandow to Temple (South to North). There was CSC congestion for about 16.7% of the intervals during our test time period. Table 3.1 lists the monthly summary of the congested intervals for South to Houston CSC (S-H), South to North (S-N), West to North (W-N), North to West (N-W), and total CSCs during test months.

Table 3.1: CSC Congestion Frequency

Month	S-H (intervals)	S-N (intervals)	W-N (intervals)	N-W (intervals)	Total (intervals)	Percentage
Jan-02	661	1030	0	0	1520	51.1%
Feb-02	356	501	57	0	834	31.0%
Mar-02	29	243	79	90	432	14.5%
Apr-02	122	99	329	212	741	25.7%
May-02	267	10	27	38	334	11.2%
Jun-02	677	335	24	115	1067	37.1%
Jul-02	505	477	0	221	997	33.5%
Aug-02	380	172	0	140	649	21.8%
Sep-02	565	18	0	70	649	22.5%
Oct-02	54	4	49	88	189	6.3%
Nov-02	0	2	0	29	31	1.1%
Dec-02	0	41	2	18	61	2.1%
Jan-03	59	25	0	0	84	2.8%
Feb-03	9	56	0	0	65	2.4%
Mar-03	259	163	5	0	412	13.8%
Apr-03	270	103	0	0	373	13.0%
Total	4069	3160	365	838	7789	16.7%

Normally, transmission congestion should be less serious during the low demand period of winter. The reason for the high congestion frequency in January 2002 and February 2002 was that the CSC congestion "re-dispatch cost" was uplifted among market participants on a "load ratio share" since the ERCOT ISO began operation as a single "control area" on July 31, 2001. This presented an opportunity for profiting by over-scheduling load and then being paid to relieve congestion. After February 15, 2002, the charge or payment related to CSC congestion to a QSE is based on its scheduled flow and their TCR ownership on the congested CSCs. Therefore the CSC congestion frequency decreased and the over-scheduling problem was not found during the other months of our analysis period.

By neglecting "intrazonal" constraints within the four congestion zones, the ERCOT market can be simplified to a four-node system. Based on the competitive benchmark model in Section 3.2, separate cost curves for each zone should be developed to estimate marginal costs. Marginal costs will be the same for all zones if no constraint on CSCs is binding. In case of CSC congestion, marginal cost will be different in each zone. Because of the CSCs' congestion, some expensive resources have to be deployed to meet the system demand even though cheaper sources may be available in other zones.

The zonal cost curve depends on the availability, cost structures of generation resources in each zone, and fuel prices in ERCOT. The installed generation capacities of ERCOT were about 77,000 MW in 2002, and 79,000 MW in 2003, respectively (EIA (2002a), PUCT (2003a)). Table 3.2 shows the generation mix of ERCOT by capacity during 2002 and 2003.

Table 3.2: Generation Capacity Mix in ERCOT

Resource	2002	2003
Natural Gas	68.9%	72.6%
Coal & Lignite	23.3%	21.2%
Nuclear	5.6%	5.9%
Wind	1.1%	1.2%
Hydro	0.7%	0.7%
Others	0.4%	0.4%

From Table 3.2 we can see that more than 90% of the installed capacities in ERCOT are fossil fuel units. In developing the zonal cost curve, we assume that all capacities of nuclear units are available because nuclear generators always supply the base load and their forced outage rate is very low. Due to the dependence on weather conditions, it is impractical to model the production cost for hydro and wind generation units explicitly. We assume 50% of hydro and wind capacities are available. Since the hydro and wind generation together account for only about 1.9% of the installed capacity in ERCOT, and their generation cost is very low, this assumption will have little effect on our analysis about the balancing energy market. In addition, the system demand is always much larger than the total capacity of nuclear, wind, and hydro units. Therefore we formulate the zonal cost curve only considering coal units and natural gas units. The capacity of the other resources in each zone will be deducted from the zonal demand, and their effects on CSC are considered. If those units ever become the marginal unit in the balancing market, our results could overestimate the marginal cost.

For fossil fuel generation units, the production cost for each unit is based on the fuel price and its average heat rate, which is a common assumption in the literature. The average heat rate for each unit is obtained from (Henwood (2002), EPA (2002), PUCT (2002)). Although incremental unit heat rate curve would be more appropriate, this information is not available to us. The gas prices are obtained from the Market Oversight Division (MOD) at the Public Utility Commission of Texas (PUCT). Coal prices are from (EIA (2002b)). No attempt is made to capture the operating, planned maintenance, environmental cost, and ancillary services purchased in the ERCOT day-ahead market. Ignoring those factors could lead us to underestimate the marginal cost. However, forced outage has been considered through derating unit capacity by its forced outage rate.

For each zone, a heat rate curve was developed for the units within the zone. Assume there are m generation units in ERCOT, indexed by $j = 1,2,\cdots,m$. The average cost c_{ji} for each MW of electricity generated by unit j in zone $i = 1,2,\cdots,n$, is:

$$c_{ji} = (p_c(1-\varphi_j) + p_g\varphi_j)h_j, \tag{3.41}$$

where

p_c	Price for coal, \$/MMBtu;
p_g	Price for natural gas, \$/MMBtu;
φ_j	Fuel type of generation unit j; 0 if coal, 1 if gas;
h_j	Heat rate for generation unit j, MMBtu/MWh.

All m_i units in a zone are sorted by increasing average cost of each MW of electricity production, so that $c_{1i} \le c_{2i} \le \cdots \le c_{m_i i}$ in zone i. Then the approximate marginal cost curve for zone i will be:

$$\begin{aligned} & g_i(q_i) = c_{ji,} \\ if \quad & \sum_{k=1}^{k=j-1} b_{ki} \le q_i \le \sum_{k=1}^{k=j} b_{ki}, \end{aligned} \tag{3.42}$$

where

$g_i(q_i)$ The marginal cost for q_i MW supply in zone i;

b_{ji} The the average capacity for unit j in zone i, which equals to its installed capacity times (1- r_j);

r_j The forced outage rate of generation unit j based on the NERC outage probability statistics (NERC (2002)).

The zonal cost curve is:

$$C_i(q_i) = \int_0^{q_i} g_i(q)dq \tag{3.43}$$

By the nodal cost function (3.43), the actual zonal load, and CSC transmission capacities published by the ERCOT ISO every 15 minutes during January 2002 and April 2003, the ERCOT competitive benchmark model is constructed as (3.7)-(3.10) for each interval during the test time period. The object is to minimize the total production cost of the whole market subject to the supply demand balance constraint, the CSC transmission limit constraints, and zonal generation capacity constraints.

$$\begin{aligned} Min \quad & \sum_{i=1}^{n} C_i(q_i) \\ s.t. \quad & \sum_{i=1}^{n} (q_i - d_i) = 0, \\ & \sum_{i=1}^{n} s_{ki}(q_i - d_i) \le FL_k \quad \forall k \in K, \\ & q_i \le q_{i\max} \quad \forall i \in n, \end{aligned}$$

where

i Index of zone, $i = 1,2,\cdots,4$;

s_{ki} Shift factor of zone i on CSC k;

FL_k Capacity limit of CSC k;

q_i Generation output at zone i;

$q_{i\max}$ Generation capacity limit at zone i;

d_i Demand of zone i.

Although the competitive benchmark will be applied to the ERCOT balancing energy market, which accounts for only 3%-5% of the energy consumption in ERCOT, the actual system load for every 15 minutes interval of the ERCOT market is used to clear the competitive benchmark model. Market participants reflect their bilateral contracts in their portfolio schedules. We assume market participants use the cheapest or most efficient units to supply their native load to meet their bilateral contract obligations, and bid the extra available capacity to the balancing energy market. In other words, we assume that the pattern of dispatch is equivalent to that of a centralized energy pool market and that the balancing energy is the marginal part for the clearing of system load.

The impact of resources and load within a commercial congestion zone on the CSCs transmission constraints is reflected by the zonal generation weighted average shift factors, which are determined by the ERCOT ISO monthly based on known topology of the ERCOT system. Any imbalance between loads and generation resources in a congestion zone is assumed to have the same impact on a given CSC. The resulting flows of all dispatched generations on the CSCs have to be within their transmission capacity.

By (3.34), the zonal marginal competitive price θ_i can be obtained. When there is CSC congestion, the zonal competitive prices will differ from zone to zone. The generation weighted average competitive price for the system demand $\hat{D} = [D_1, D_2, \cdots D_n]$ is:

$$\bar{\theta}(\hat{D}) = \frac{\sum_{i=1}^{n} \theta_i q_i}{\sum_{i=1}^{n} q_i}. \qquad (3.44)$$

3.3.2 Application Result

The estimated competitive benchmark prices were compared to the actual BEM prices to estimate an efficiency index called the Lerner Index (LI) for the ERCOT BEM. The ERCOT ISO determines and posts the Zonal Market Clearing Prices

(MCPE) of balancing energy services (BES) for every 15 minutes interval, which we refer to as the actual market price.

BES includes Balancing Energy Up (BEU) and Balancing Energy Down (BED). Since BEU and BED are settled differently, we estimate their indices separately. For BEU, the LI is defined as the percentage of the difference between the actual market price and marginal cost (actual market price – marginal cost) divided by the actual market price. The LI for the BED is defined as the difference between marginal cost and the actual market price divided by the actual market price. We adopted a quantity weighted LI to estimate the competitiveness of BES.

The weighted average BES price (we refer to weighted average as simply the average in this chapter), $\overline{p}_t^{\pi}$, at interval t is defined as:

$$\overline{p}_t^{\pi} = \frac{\sum_{i=1}^{n} p_{it}^{\pi} q_{it}^{\pi}}{\sum_{i=1}^{n} q_{it}^{\pi}} \qquad \pi = u, d\,, \tag{3.45}$$

where

π The index of BES: u is for BEU and d is for BED;

p_{it}^{π} The actual zonal market price for BES π at interval t;

q_{it}^{π} The zonal deployed MW for BES π at interval t.

The weighted LI over T time periods for BEU and BED is

$$L_T^{\pi} = \frac{\sum_{t=1}^{T} \sigma_{\pi} (\overline{p}_t^{\pi} - \overline{\theta}_t) q_t^{\pi}}{\sum_{t=1}^{T} \overline{p}_t^{\pi} q_t^{\pi}}, \qquad \pi = u, d\,, \tag{3.25}$$

where

π The index of BES: u is for BEU and d is for BED; $\delta_u = 1$ and $\delta_d = -1$;

$\overline{\theta}_t^{\pi}$ The competitive benchmark price at interval t developed from the above competitive benchmark model;

q_t^{π} The net balancing energy deployment for interval t.

Because the BEU price represents the price paid by the ERCOT ISO to QSEs, a higher BEU index means a larger market price deviation from the competitive price. In contrast, the BED price is paid by QSEs to the ISO. Therefore, a lower BED price means more deviation from the competitive price. The factor $\delta_d = -1$ in the BED index definition means that a higher BED LI corresponds to a larger negative deviation of BED price from the competitive price.

Table 3.3: Monthly LI of BEM

Month	Gas Price ($/mmbtu)	MC (BEU) ($/MWh)	MC (BED) ($/MWh)	Actual (BEU) ($/MWh)	Actual (BED) ($/MWh)	LI BEU	LI BED
Jan-02	2.25	20.86	22.03	22.66	6.59	8.0%	234.4%
Feb-02	2.30	21.51	21.78	27.16	9.67	20.8%	125.3%
Mar-02	3.07	28.05	27.46	32.34	13.11	13.3%	109.4%
Apr-02	3.44	34.20	31.38	47.70	17.44	28.3%	79.9%
May-02	3.50	32.71	33.03	34.47	15.38	5.1%	114.8%
Jun-02	3.24	33.27	31.86	35.07	17.74	5.1%	79.6%
Jul-02	3.02	30.83	29.29	33.07	16.55	6.8%	77.0%
Aug-02	3.09	31.34	31.24	31.20	17.85	-0.5%	75.1%
Sep-02	3.53	35.09	34.03	33.46	15.56	-4.9%	118.6%
Oct-02	4.03	38.05	34.43	42.54	17.34	10.6%	98.5%
Nov-02	3.93	36.53	34.05	35.38	14.01	-3.3%	143.0%
Dec-02	4.55	43.57	39.97	40.28	11.74	-8.2%	240.4%
Jan-03	5.21	51.86	48.46	52.49	17.78	1.2%	172.6%
Feb-03	7.59	86.39	46.47	102.43	19.31	15.7%	140.6%
Mar-03	6.00	66.47	42.68	74.70	31.04	11.0%	37.5%
Apr-03	5.21	50.53	42.04	59.83	16.57	15.6%	153.8%
Average	4.00	46.97	32.82	51.56	16.15	8.9%	103.3%

The monthly average of gas price, marginal cost (MC), BES price, and LI of the ERCOT BES market form January 2002 to April 2003 are summarized in Table 3.3. Some intervals were excluded from the index calculation in order to avoid the influence of abnormal events, such as forced outages, software failures, and operation errors (ERCOT (2003a)). There are a total of 464 intervals excluded for the testing time period, which account for only about 0.9% of the total test intervals. For the abnormal intervals, the average LI of BEU was 79.8%, and the average LI of BED was 137.7%.

The reason for the high indices of the abnormal intervals is that MCPEs of some abnormal intervals were higher than $900/MWh or lower than –$100/MWh.

3.3.3 Result Analysis

In order to benchmark the performance of the ERCOT BES market, we need to compare it with other restructured electricity markets. Bushnell and Saravia (2002) found the average LI of the New England electricity day-ahead market from May 1999 to September 2001 to be 12%. The average LI of the PJM, California, and New England day-ahead market from May 1999 to December 1999 were estimated to be 25%, 17%, and 10%, respectively.

Because the ERCOT market opened later than the PJM, the California, and the New England markets, there is no overlap of the time period between our analysis and Bushnell and Saravia's study. However, we can still usefully compare the ERCOT market index with their results, because they all concern the early stages of market operations.

However, we should note that all the analysis of the other restructured markets besides ERCOT is for day-ahead markets and not of a real-time balancing market. We will only compare the BEU indices of ERCOT to the indices in the literature for day-ahead market. Since day-ahead markets have a different role from that of real-time balancing markets, results for day-ahead and balancing markets should be compared with caution.

As seen from Table 3.3, the LI of BEU in the ERCOT BES market ranges from –8.2% to 28.3% and the average is about 8.9% during the 16 sample months. The average BEU LI is only 2% from May to December 2002, including the abnormal intervals. Compared with the index of other markets for the similar months, from May to December 1999, the performance of BEU in ERCOT is favorable during the period.

On the other hand, the BED market in ERCOT is relatively inefficient compared with its BEU market. The LI of BED ranges from 37.5% to 234.4%, and averages about 103.3% for the whole period. It is much higher than the average index for the BEU.

The high capacity reserve margins in ERCOT presumably contributed to the competitive performance of the BEU market. Several circumstances, including the transmission interconnection rules and renewable energy credit-trading program, have encouraged significant new generation investments in ERCOT since 1995. The reserve margins were 34% and 21% for 2002 and 2003, respectively. The high volume of bilateral contracts provides mitigation against the effects of the market power, which presumably also contributed to the competitive BEU market. The analysis in Chapter 4 will show the effects of forward contracts on the ERCOT market results.

However, attention should be paid to the high index of the BED market, which indicates that the QSEs bid prices that were lower than marginal cost, and were reluctant to decrease their output or take part in the BED market. In ERCOT, BEU and BED bid curves consist of monotonically increasing ordered pairs of dollars per megawatt-hour and cumulative megawatts ($/MWh, MW). The ERCOT ISO orders all bids received for BEU hourly from the lowest bid price to the highest bid price, and BED hourly bids from the highest bid price to the lowest bid price. These combined bid curves are called the BEU and BED bid stack respectively. The hourly weighted average bid price (WABP), $\overline{p}_h^\pi$, is defined as follows:

$$\overline{p}_h^\pi = \frac{\sum_{j=1}^{N_h^\pi} p_{hj}^\pi b_{hj}^\pi}{\sum_{j=1}^{N_h^\pi} b_{hj}^\pi}, \qquad \forall h, \pi = u, d \, , \tag{3.47}$$

where

h	The index of hour, $h = 1, 2, \ldots, 24$;
p_{hj}^π	The bid price of BES π at block j;
b_{hj}^π	The bid quantity of BES π at block j;
N_h^π	The number of blocks for BES π at hour h.

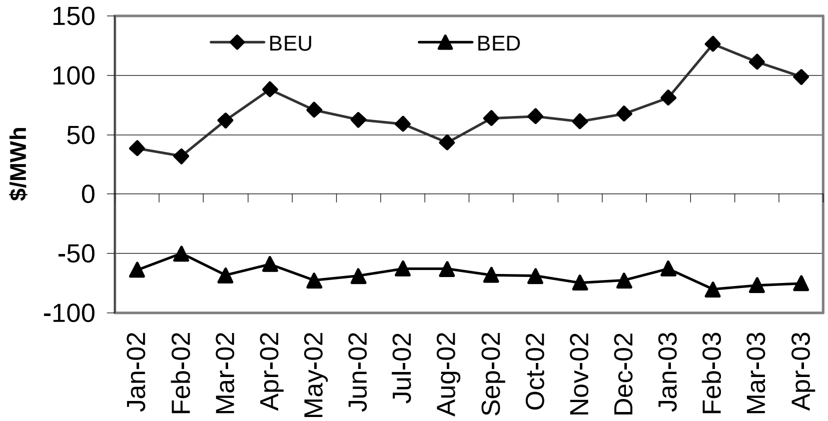

Figure 3.2: The Weighted Average Bid Price of BED and BEU

Figure 3.2 shows that the monthly average bid price of BEU and BED. The WABP of BED is much lower than that of BEU. This means that QSEs submit very low or negative BED bid prices in order to avoid being "balanced down." Avoiding BED deployment could limit the mechanical damage of frequent up and down movements. Because market participants self commit their units and only one-part bidding (energy bid) is permitted in the ERCOT BES market, the balancing down bids must recover any subsequent start-up cost if balancing down necessitated a shut-down. Participants usually arrange the unit commitment one day ahead to decide the sequence of their on-line units. Units may be constrained by their minimum generation limits during off-peak hours, and QSEs may be reluctant to deploy their units for BED to avoid possible shut down of units. During on-peak hours, these limits are relatively relaxed. Therefore QSEs would presumably prefer to decrease their generation during on-peak hours if they can find cheaper suppliers to meet their demand. Figure 3.3 compares the LI of BES during on-peak and off-peak hours for each month from January 2002 to April 2003. Off-peak hours refer to the hours ending 23:00 to 6:00, while on-peak hours refer to the hours ending 7:00-22:00.

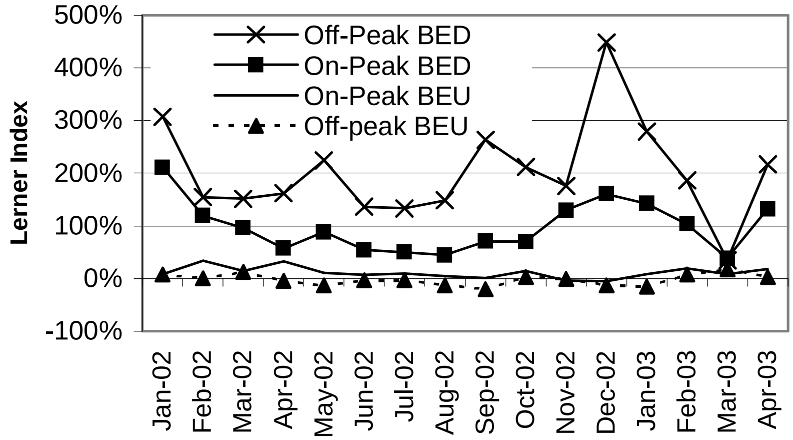

Figure 3.3: Lerner Index of Peak and Off-Peak Hours

As shown in Figure 3.3, the LI of BED during off-peak hours was higher than those of on-peak hours, except for March 2003, when the indices were very close. This suggests that the unit commitment and lower generation limits affected the BED index, and could contribute to the high BED index. Even though the BED indices were relatively lower during on-peak hours, they were still much higher than the BEU indices. This could result in inefficient dispatch. Similarly, we can find that the unit commitment and generation limits also affect the BEU index, because LI of BEU during off-peak hours was lower than those of on-peak hours for most of the months. During off-peak hours, QSEs would presumably consider increasing generation from on-line generators, since the output is well under their upper limits during that time. On the other hand, the upper operation limits are relatively tight during on-peak hours.

In addition to the unit commitment and operational limits, other factors such as the gas pipeline transportation and inventory limits can also be the reasons for the high BED index. In addition, frequent increasing and decreasing generation output is harmful to the turbines of generation units. QSEs could avoid this machine damage by bidding low or negative BED price to prevent them from being dispatch BED. So lower or negative BED bid price may reflect the costs of damage or adjustment cost.

Furthermore, during the period we study, the ERCOT market still had design flaws that may have contributed to inefficient dispatch and market pricing. However, the flaw would be benign if firms acted as pure price takers, rather than exploiting these design flaws to affect the market price. Bad judgment and confusion on the new market of some generators may also contribute the inefficiencies of balancing down energy market of ERCOT. Some participants may not like to take part in the ERCOT BED market even though there may be cheaper suppliers available.

3.4 APPLICATION OF TRANSMISSION AND OPERATION CONSTRAINTS ANALYSIS MODELS

Even though the competitive benchmark approach identified that the ERCOT market deviates from the competitive outcomes (relatively small deviation for BEU, but considerable deviation for BED), it is not informative about the specific reasons for the deviations. Market power and technical constraints such as unit commitment, operational constraints, and transmission limits could be some other possible reasons.

It is impossible to find all the reasons for the departure from the competitive pricing and quantify their effects. Considerable work (Hogan (1992, 1997), Oren (1997), Joskow, and Tirole (2000)) focuses on how transmission congestion can increase market power. Operational constraints could potentially also be manipulated by participants to force the ISO to dispatch their units profitably. Since CSC transmission constraints and operational constraints (portfolio BEU and BED ramp rate) are the two major constraints in the ERCOT BEM clearing process (ERCOT (2002b)) during our test time period, we will focus only on these two factors and develop models to quantify their effects on market performance. By effects of CSC or operational constraints, we mean how much these constraints influence MCPE, given the participant's actual BEM bids and schedules. Market power could be reflected in the result, but we do not intend to separate the impacts of market power from other issues.

3.4.1 ERCOT Model Formulation

Actual market prices reflect the effects of both operational and CSC constraints as the market clearing mechanism discussed in Section 3.2. In order to analyze the effects of CSC and operational constraints, we developed Non-Constrained Model (NCM) and Transmission Constrained Model (TCM) for the ERCOT market based on the actual BES bids as discussed in Section 3.2. But we have to consider schedules submitted by QSEs for the ERCOT models. The clearing quantities are set to be the actual system BES demands. The objective of NCM is to minimize the total system cost based on the BES bid stack and schedules submitted by QSEs. The NCM is shown as follows.

$$Min(\sum_{j=1}^{N_Q}\sum_{i=1}^{n}\int_0^{q_{ji}^u} f_{ji}^u(q)dq - \sum_{j=1}^{N_Q}\sum_{i=1}^{n}\int_0^{q_{ji}^d} f_{ji}^d(q)dq) \tag{3.48}$$

$$s.t. \qquad \sum_{j=1}^{N_Q}\sum_{i=1}^{n} S_{ji} - \sum_{i=1}^{n} D_i + \sum_{j=1}^{N_Q}\sum_{i=1}^{n}(q_{ji}^u - q_{ji}^d) = 0, \tag{3.49}$$

$$q_{ji}^u \le U_{ji}, \qquad \forall j \in I_Q, \tag{3.50}$$

$$q_{ji}^d \le R_{ji}, \qquad \forall j \in I_Q, \tag{3.51}$$

where

I_Q	The set of QSEs;
N_Q	Number of QSEs;
$f_{ji}^u(q_{ji}^u)$	BEU bid curve for QSE j in zone i;
$f_{ji}^d(q_{ji}^d)$	BED bid curve for QSE j in zone i;
q_{ji}^u	Deployed MW of BEU for QSE j in zone i;
q_{ji}^d	Deployed MW of BED for QSE j in zone i;
S_{ji}	Total generation schedule for QSE j in zone i;
U_{ji}	BEU bid quantity for QSE j in zone i;
R_{ji}	BED bid quantity for QSE j in zone i.

Since there is no CSC constraint in NCM, the MCPE will be the same for all zone: $p_i = \mu$, where μ is the shadow price for the power balance constraint (3.49).

The TCM is formulated as an optimization problem by adding the following CSC constraints to the NCM.

$$\sum_{i=1}^{n}\sum_{j=1}^{N_Q}(S_{ji} + q_{ji}^u - q_{ji}^d) - D_i)s_{ik} \le FL_k \tag{3.52}$$

The zonal MCPE of TCM can be calculated as in (3.40). The objectives for those models are to minimize system cost. If the BEU and BED bid stack are considered separately, lower system cost always means lower MCPE. However, if some BEU bid prices are lower than some BED bid prices, known as overlap, lower system cost does not always indicate lower MCPE. Figure 3.4 shows an example of this situation. There was overlap for about 43.2% of intervals during the test period.

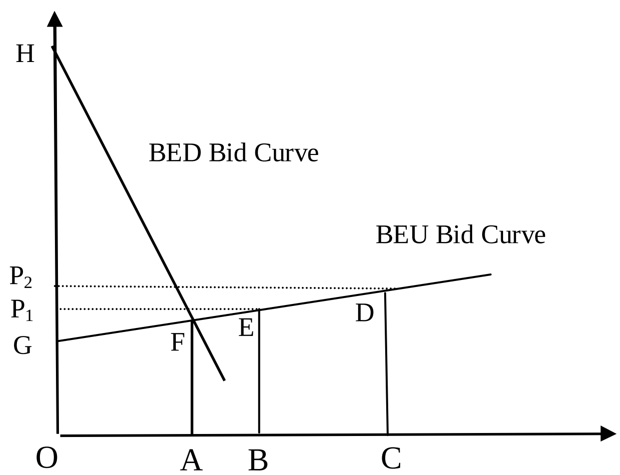

Figure 3.4: Overlap in the BES Market Clearing Mechanism

In Figure 3.4, we assume BEU demand is B MW. If we only consider BEU bid curve, the MCPE should be P_1, and the system cost is area OBEG. However, there is overlap between BEU and BED bid curve. If C MW BEU and A MW BED (C - A = B) are deployed, the BEU demand is still satisfied and the system cost changes by area (BCDE – GFH). If area BCDE is less than area GFH, the system cost will decrease. Therefore MCPE will be P_2, even though it is higher than P_1. The reason is that the ISO's objective is to minimize system cost, not to minimize the expected MCPE. Similarly, higher system cost does not always mean higher MCPE. The operational and CSC constraints always increase system cost, but they may not have the same effect on market prices. Table 3.4 shows a similar example case.

Table 3.4: Market Clearing Example with Overlap

Unit	MC $/MWh	Capacity MW	Schedule MW	BEU Bid MW/Bid Price	BED Bid MW/Bid Price	BES Deployment
Unit 1	5	60	50	10MW @ $5/MWh	50MW @ $5/MWh	10
Unit 2	10	60	40	20MW @ $10/MWh	40MW @ $10/MWh	5
Unit 3	15	50	10	40MW @ $15/MWh	10MW @ $15/MWh	-10

In the above example, we assume all units bid their marginal cost. The scheduled total generation is 100 MW. Therefore, the ISO needs 5 MW BEU to meet the system demand. To minimize the cost to supply the 5 MW balancing energy, the ERCOT ISO will dispatch 10 MW BEU to unit 1 and 5 MW BEU to unit2, and 10 MW BED to unit 3. The MCPE will be $10/MWh. In this case, there is overlap between BEU and BED bid. Unit 3 would like to pay $15/MW to other cheaper generator to cover its own load. If the unit 3 bid 10 MW BED at $3/MW, the ERCOT ISO will only dispatch 10 MW to unit 1. No balancing energy will be dispatched to unit 2, and unit 3. Since the BED bid of unit 3 is lower than the marginal cost of unit 1 and unit 2, no BEU is deployed to cover the load of unit 3. The MCPE for this case will be $5/MWh.

3.4.2 Application Results

Based on the submitted BES bid stacks, actual zonal load, BES demand, zonal generation schedule, and CSCs transmission capacities, market prices of the NCM and the TCM were calculated for all the intervals by simulating the market during January 2002 and April 2003, excluding the abnormal intervals mentioned in section 3.3. Excluding these intervals avoids the bias from the abnormal conditions. Tables 3.5 and 3.6 show the average BES price results for NCM and TCM respectively.

Table 3.5: BEU Prices ($/MWh)

BEU Price	Un-congested		Congested Intervals			Total Intervals		
	NCM	Actual	NCM	TCM	Actual	NCM	TCM	Actual
Jan-02	20.78	21.11	20.41	23.45	24.23	20.60	22.11	22.66
Feb-02	20.51	21.10	21.73	25.27	35.78	21.01	22.47	27.16
Mar-02	31.62	32.77	27.90	29.55	30.45	30.94	31.25	32.34
Apr-02	36.03	35.94	37.66	42.45	79.77	36.47	37.75	47.70
May-02	34.05	34.52	31.30	32.98	33.32	33.94	34.01	34.47
Jun-02	33.27	33.67	33.63	36.72	36.82	33.43	34.81	35.07
Jul-02	32.57	32.86	30.55	38.42	33.58	31.98	34.27	33.07
Aug-02	29.98	30.46	31.67	34.02	34.28	30.31	30.76	31.20
Sep-02	31.57	31.82	33.54	38.42	38.53	32.05	33.24	33.46
Oct-02	38.89	41.71	40.43	45.88	52.57	39.01	39.43	42.54
Nov-02	34.66	35.35	32.67	40.49	40.10	34.65	34.69	35.38
Dec-02	39.24	40.23	39.54	40.76	41.44	39.26	39.31	40.28
Jan-03	51.00	52.50	47.69	47.60	52.23	50.94	50.94	52.49
Feb-03	98.92	103.54	55.47	61.78	63.93	97.70	97.88	102.43
Mar-03	67.76	71.81	70.85	84.31	86.19	68.38	71.09	74.70
Apr-03	55.41	57.85	47.74	67.86	74.77	54.51	56.87	59.83
Average	51.21	53.17	35.15	41.03	43.05	48.66	49.59	51.56

Table 3.6: BED Prices ($/MWh)

BED Price	Un-congested		Congested Intervals			Total Intervals		
	NCM	Actual	NCM	TCM	Actual	NCM	TCM	Actual
Jan-02	7.91	7.71	11.29	5.82	4.97	9.30	7.06	6.59
Feb-02	9.95	9.89	10.75	8.89	9.11	10.18	9.65	9.67
Mar-02	12.71	13.22	13.87	12.15	12.28	12.84	12.65	13.11
Apr-02	16.91	17.48	18.87	16.90	17.33	17.42	16.91	17.44
May-02	15.92	15.17	19.21	16.95	16.73	16.36	16.06	15.38
Jun-02	16.93	16.75	23.46	19.29	19.48	19.30	17.79	17.74
Jul-02	17.51	16.64	19.09	17.18	16.41	18.12	17.39	16.55
Aug-02	17.39	17.22	21.36	19.43	19.56	18.45	17.93	17.85
Sep-02	15.50	14.95	21.43	18.07	18.47	16.53	15.95	15.56
Oct-02	17.38	17.16	24.66	23.40	23.22	17.60	17.56	17.34
Nov-02	14.39	14.00	17.31	15.60	15.84	14.41	14.40	14.01
Dec-02	11.34	11.73	27.76	28.00	29.54	11.35	11.35	11.74
Jan-03	17.47	17.74	28.25	27.40	20.51	17.61	17.60	17.78
Feb-03	18.84	19.26	41.31	38.02	26.97	19.00	18.98	19.31
Mar-03	29.53	30.73	39.84	40.21	36.72	30.08	30.10	31.04
Apr-03	14.95	15.16	27.38	27.42	22.90	17.21	17.22	16.57
Average	16.15	16.16	19.09	16.42	16.09	16.73	16.20	16.15

Tables 3.7 and 3.8 compare the LI index based on the estimated prices of the NCM, TCM, and the actual market price for the un-congested intervals and congested intervals respectively.

Table 3.7: LI for Un-congested Intervals

Month	BEU		BED	
	NCM	Actual	NCM	Actual
Jan-02	-2.1%	-0.5%	178.5%	185.9%
Feb-02	-5.9%	-3.0%	121.9%	123.3%
Mar-02	10.9%	14.0%	116.5%	108.2%
Apr-02	6.4%	6.1%	86.4%	80.2%
May-02	4.0%	5.3%	107.0%	117.3%
Jun-02	0.2%	1.4%	87.4%	89.4%
Jul-02	5.4%	6.2%	67.4%	76.1%
Aug-02	-3.3%	-1.7%	79.6%	81.4%
Sep-02	-10.6%	-9.8%	117.9%	125.9%
Oct-02	2.8%	9.3%	97.8%	100.3%
Nov-02	-5.4%	-3.4%	137.0%	143.6%
Dec-02	-11.0%	-8.3%	252.6%	240.8%
Jan-03	-1.6%	1.3%	177.3%	173.1%
Feb-03	12.3%	16.2%	146.2%	140.9%
Mar-03	1.0%	6.6%	43.5%	38.0%
Apr-03	8.7%	12.6%	172.4%	168.7%
Average	4.0%	7.6%	106.7%	106.5%

As shown in Table 3.7, for the un-congested intervals of the test period, the average LI indices for the NCM and the actual market price are 4.0% and 7.6%, respectively. As we discussed in Section 3.2.3, by comparing the results of NCM and the actual market clearing mechanism, we observe that operational constraints increase the average BEU index by 3.6% from 4.0% to 7.6%. But the average BED index changed only 0.2%, which means that the operational constraints did not affect the BED performance much for the un-congested intervals.

For the congested intervals of the test period in Table 3.8, the operational and CSC constraints increased the average BEU index by an average of 18.9%, from –1.3% to 17.6%, with a 14.9% (from –1.3% to 13.6%) increment due to CSC congestion and a 4% (from 13.6% to 17.6%) increment due to the operational constraints. At the same time, the CSC congestion and operational constraints contributed an average of 26.4% increment to the BED index (from 63.9% to 90.3%), with a 22.5% (from 63.9% to 86.4%) increment due to CSC congestion and a 3.9% (from 86.4% to 90.3%) increment due to operational constraints. Independence between the CSC and operational constraints is assumed in the above discussion because the operational constraint information is not available in public. In summary, both of the CSC congestion and operational constraints contribute to the BES market results, with the CSC congestion having more effect than the operational constraints during our test period.

Table 3.8: LI for Intervals with Congestion

Month	BEU			BED		
	NCM	TCM	Actual	NCM	TCM	Actual
Jan-02	-3.2%	12.6%	15.4%	97.5%	278.5%	342.9%
Feb-02	0.8%	16.1%	40.7%	102.4%	136.5%	130.8%
Mar-02	-1.5%	7.0%	9.7%	101.1%	122.3%	120.0%
Apr-02	5.7%	16.5%	55.5%	72.7%	83.4%	78.9%
May-02	-7.3%	-0.5%	0.5%	83.4%	97.8%	100.5%
Jun-02	1.0%	9.2%	9.4%	38.0%	66.5%	64.9%
Jul-02	-0.6%	19.7%	8.1%	54.9%	70.3%	78.4%
Aug-02	-2.8%	3.5%	4.2%	46.9%	60.9%	59.8%
Sep-02	-5.8%	7.4%	7.6%	66.7%	95.0%	90.8%
Oct-02	0.9%	11.1%	22.4%	47.3%	53.0%	54.2%
Nov-02	-1.1%	16.9%	16.1%	75.7%	66.5%	64.0%
Dec-02	-11.0%	-7.1%	-5.4%	50.2%	50.7%	42.8%
Jan-03	-14.5%	-14.8%	-4.6%	75.9%	81.3%	142.2%
Feb-03	-35.4%	-20.2%	-16.1%	39.7%	51.4%	113.5%
Mar-03	8.8%	24.0%	25.7%	18.7%	19.3%	30.7%
Apr-03	-4.9%	26.0%	32.8%	73.8%	74.9%	109.4%
Average	-1.3%	13.6%	17.6%	63.9%	86.4%	90.3%

Since the NCM does not consider operational and CSC constraints, the result only indicates the effect of the participants' bids. For all the congested and un-congested normal intervals during the test 16 months, the average index of NCM was 3.4% for BEU and 97.0% for BED as shown in Table 3.9. Compared with the actual BEU index of 8.9% and BED index of 103.3%, CSC congestion and operational constraints increased the average BEU index by 5.5%, and the average BED index by

3.3%. That is, the CSC and operational constraints did not contribute very much to the high BED market index. Therefore the high BED index indicates inefficient BED bid behaviors or other un-modeled operational constraints, and the low BEU index indicates relatively efficient BEU bid behaviors in the ERCOT BES market from January 2002 to April 2003.

Table 3.9: LI for All Intervals of Test Months

Month	BEU			BED		
	NCM	TCM	Actual	NCM	TCM	Actual
Jan-02	-2.6%	5.7%	8.0%	138.2%	212.3%	234.4%
Feb-02	-3.1%	4.3%	20.8%	116.1%	125.8%	125.3%
Mar-02	8.9%	10.2%	13.3%	114.6%	117.1%	109.4%
Apr-02	6.2%	9.4%	28.3%	82.5%	85.6%	79.9%
May-02	3.6%	3.8%	5.1%	103.3%	105.7%	114.8%
Jun-02	0.5%	4.4%	5.1%	65.6%	79.1%	79.6%
Jul-02	3.7%	10.0%	6.8%	62.3%	68.5%	77.0%
Aug-02	-3.2%	-1.9%	-0.5%	69.5%	74.2%	75.1%
Sep-02	-9.4%	-5.6%	-4.9%	106.3%	113.4%	118.6%
Oct-02	2.6%	3.5%	10.6%	95.7%	96.1%	98.5%
Nov-02	-5.4%	-5.3%	-3.3%	136.5%	136.5%	143.0%
Dec-02	-11.0%	-10.8%	-8.2%	252.2%	252.2%	240.4%
Jan-03	-1.8%	-1.8%	1.2%	175.2%	175.4%	172.6%
Feb-03	11.6%	11.7%	15.7%	144.5%	144.8%	140.6%
Mar-03	2.6%	6.5%	11.0%	41.8%	41.8%	37.5%
Apr-03	7.4%	11.2%	15.6%	143.9%	144.2%	153.8%
Average	3.4%	5.3%	8.9%	97.0%	102.6%	103.3%

The factors discussed in section 3.3 could have contributed to the inefficient BED bid behavior. These include unit commitment, operational limits, and unwillingness to take part in the ERCOT real-time market. Three-part bid (energy, start-up, and no load cost bid), centralized unit-commitment, day-ahead energy market, and the BES market power mitigation approaches discussed in the ERCOT market redesign process could be helpful to increase the efficiency of forward decisions and BED market.

3.5 CONCLUSIONS

In this chapter, models are developed to estimate the competitive benchmark with transmission and operational constraints and how transmission and operational constraints affect market prices based on actual market bids. These models are applied to simulate the ERCOT real-time energy market for the time period from January 2002 to April 2003. The results show that the balancing up energy market is relatively efficient with an average Lerner Index of 8.9%, and the balancing down market is relatively inefficient with an average Lerner Index of 103.3%.

It is observed that operational constraints changed the average BEU index by 3.6% and average BED index by 0.2% for the test time period. For the congested intervals of the test period, the operational constraints contribute about 4.0% increment of the average BEU index and 3.9% increment of the average BED index. Furthermore, CSC constraints increased the average BEU index by 14.9% and the average BED index by 13.5%. Independence between the CSC and operational constraints is assumed in the above discussion. For the un-congested intervals of the test period, we observe that operational constraints increase the average BEU index by 3.6% and the average BED index by 0.2%. Both CSC and operational constraints increased the average BEU index by 5.5%, and the average BED index by 3.3% for the test period including both congested and un-congested intervals.

In summary, both of the CSC congestion and operational constraints contribute to the BES market result during our test period. CSC congestion had more effect on market performance than did operational constraints. However, the operational constraints and CSC congestion does not contribute much to the inefficiency of the balancing down energy market. The possible market power (bid strategies) related to transmission constraints and operational constraints are not considered in this chapter.

The high bilateral contract volume and high capacity reserve margin could contribute to the relatively efficient balancing up energy market. Unit commitment, lower generation limits, market power, and the unwillingness of some participants to take part in ERCOT balancing down market possibly contributed to the inefficient balancing down market performance.

CHAPTER 4: SUPPLY FUNCTION EQUILIBRIUM BIDDING STRATEGIES WITH FORWARD CONTRACTS

4.1 INTRODUCTION

Several characteristics of electricity markets facilitate the excise of market power, which includes nearly perfectly inelastic demand, economically prohibitive storage, limited generation and transmission capacity, and the requirement that supply and demand must balance continuously. Therefore, market power analysis has received special attention in electricity markets.

Non-collusive game theoretical approaches, such as the Cournot, Bertrand, and Supply Function Equilibrium models, are widely used to model and analyze market power in the restructured electricity markets. However, the appropriateness of the assumptions of these models for electricity market has been challenged. In the electricity market, every firm offers a price and quantity schedule (supply function) for each of its generator or entire output simultaneously to the market operator. The Supply Function Equilibrium (SFE) model initialed by Klemperer and Meyer (1989) reflect these price and quantity schedule in their assumption. Market participants submit a price and quantity function (supply or bid function) in their SFE model. At equilibrium, no player wants to unilaterally change its supply function in order to maximize its profit. The decision variables are the parameters of the supply function, rather than simple quantity or price as in the Cournot and Bertrand models. From the aspect of bid rules of electricity markets, SFE models offer a more realistic view of electricity markets.

In addition to offering a more realistic view of electricity market bidding rules, SFE models also have the ability to handle the cases with zero demand elasticity. In Cournot models, the market price is determined by the intersection of the aggregate quantity offered by all market players and the system demand or residual demand curve. If the demand or residual demand elasticity is zero, there will be no solution for Counot models. Therefore, specify the residual demand elasticity is critical and necessary for the solution of Counot modes. The existence of equilibrium in Cournot models does require the residual demand to be elastic. However, the short-run demand elasticity in electricity markets is almost zero, and it is difficult to specify the market demand curve. As a result, price predictions from Cournot models depend on assumptions about a competitive fringe, and are not reliable. Frame and Joskow (1998) mentioned that they are not aware of any significant empirical support for the Cournot model providing accurate prediction of prices in an electricity market. Although the Bertrand model does not require elastic demand, the Bertrand equilibrium is the same as the perfect competitive optimum as long as the market has at least two players with unlimited capacity. This does not match the actual market results.

In contrast, neither demand elasticity nor a competitive fringe is necessary for the existence of SFE equilibrium. The price and quantity supply functions from players creates elasticity of the residual demand faced by each player. Therefore, the existence of equilibrium in SFE model does not depend on demand elasticity or a competitive fringe. SFE models could deal with the zero demand elasticity case. The price predictions from SFE models are generally sensible, which represent an intermediate level of competition, lying between the Bertrand and Cournot results. The application of SFE models to the England and Wales electricity market (Green and Newbery (1992), and Baldick (2004)) showed that SFE models could predict price that match the empirical data reasonably.

SFE models have been used to analyze firms' bidding strategies. Since SFE models fit actual bidding rules in electricity spot markets better than Cournot models (Allaz and Vila (1993), Powell (1993)), the predicted behaviors should be more instructive. Green (1999) analyzed the relationship between the spot market and contract market with two generators. Hortacsu and Puller (2004) used an ex-post SFE model to examine the bidding behaviors in the ERCOT real-time market from September 2001 to July 2002. Anderson and Xu (2002) discuss a symmetric duopoly SFE in the case with contracts and price caps. The effects of transmission network on firms' behaviors are analyzed with single period SFE models in small networks in Younes and Ilic (1998) and Berry, Hobbs, and Meroney (1999).

In this chapter, a linear asymmetric SFE model with transmission constraints is proposed to analyze the bidding strategies with forward contracts. The research contributes to the literature in several aspects. First, we combine forward contracts, transmission constraints, and multi-period strategy (an obligation for firms to bid consistently over an extended time horizon such as a day or an hour) into the linear asymmetric SFE framework. As an ex-ante model, it can provide qualitative insights into firms' behaviors. Second, the bidding strategies related to Transmission Congestion Rights (TCRs) are discussed by interpreting TCRs as a linear combination of forwards. Third, the model is a general one in the sense that there is no limitation on the number of firms and scale of the transmission network, which can have asymmetric linear marginal costs. In addition to the theoretical analysis, we apply our model to the ERCOT real-time market. Most applications of oligopoly models focus on contract markets or day-ahead pool markets (Powell (1993), Von der Fehr, and Harbord (1993), De la Torre, Conejo, and Contreras (2003, 2004)). Our model shows that real-time market analysis is also valuable even when it is relatively small in trading quantity.

The remainder of this chapter is arranged as follows. Section 4.2 reviews the evolution of SFE models and the reasons we choose linear SFEs as our framework to analyze the effects of forward contracts on firms' bidding strategies. Section 4.3 describes the proposed SFE model with forward contracts. Optimal strategies are discussed for both transmission congested and un-congested situations. We briefly describe the assumptions of the ERCOT SFE model with forward contracts in Section 4.4. The application results of our SFE model to the ERCOT real-time balancing energy market are also presented in section 4.4. Section 4.5 concludes this chapter.

4.2 EVOLUTION OF SUPPLY FUNCTION EQUILIBRIUM MODELS

The merits of SFE models mentioned in section 4.1 have attracted many researchers to apply them to various issues related to market power in the electricity markets. These include the impact of strategic behaviors, market divesture, and transmission network on electricity prices. Green and Newbery (1992) firstly applied SFE model to the England and Wales (E&W) electricity market to investigate how divestiture will affect the market outcome. Their publication attracted a substantial interest to the SFE model both in the industry and in academia. Newbery (1998) and Green (1999) explored the effects of the contract market on the equilibrium with SFE model. Rudkevich (1999) presented a SFE model to analyze the ability of market players to adapt their behavior through market observations. Bohn, Klevorick, and Stalon (1999) tried to use an SFE model to gain insights into the bidding behavior of firms in the California Power Exchange. Ilic (1998) and Berry, Hobbs and Meroney (1999) examined how the transmission constraints affects the competition with a SFE model. Rudkevich (2002) offered an SFE model to find the effects of different payment rules ranging from the one-price to the pay-as-bid market price clearing rules. Baldick and Hogan (2002) examined the interaction of capacity constraints, price caps, and the length of the time horizon over which bids must remain unchanged on the market price.

Although the SFE model represents the bid rules of electricity markets more realistically, this realism also brings difficulty to find equilibrium at the same time. The challenge to solve SFE models is caused by the non-convexity of the optimization problem faced by each firm. Without restrictive assumptions on the SFE models and powerful algorithms, it is very difficult to find equilibrium. All the published studies with SFE models have tended to make assumptions on the number of firms, on the nature of production costs, or on the form of the bid functions to facilitate the solution of their models.

However, these simplified SFE modes face the problem of how to reduce the distortion of their representation of electricity markets. Green and Newbery (1992), Newbery (1998), and Rudkevitch (1998) restricted the marginal costs to be symmetric, with equally sized firms of the same marginal cost. The high degree of symmetry is very doubtful in an actual market, because market players normally have asymmetric cost structure. Rudkevich (1998) assumed constant marginal cost for generators in their analysis. However, actual generator or a portfolio of generators does not have constant marginal cost. Baldick and Hogan (2002) found that the assumption of constant marginal costs could result in no stable SFEs.

Those unrealistic assumptions caused the skeptics about the asserted realism of SFE models. To extend the realism merit of SFE models, asymmetric structure was proposed and applied by Turnbull (1983), Baldick and Hogan (2002), Baldick, Grant and Kahn (2004), and Green (1996, 1999). In Rudkevich (1999) and Green (1992,1996), linear marginal cost functions with zero (or all have the same) intercept have been assumed for each player. Baldick, Grand, and Kahn (2004) questioned the plausibility of the equal intercept assumption for electricity markets with heterogeneous technologies, including gas as well as coal. Baldick, Grant, and Kahn (2004) introduced unequal marginal cost intercepts for linear marginal cost functions into the SFE framework.

The advantage of the linear marginal cost function over the more general form in SFE models lies in its ability to handle asymmetric strictures when there are more than two players. But the linear marginal cost function does not guarantee the existence and uniqueness of equilibrium without further limitation on supply functions. Klemperer and Meyer (1989) showed that the condition for uniqueness of equilibrium is the unboundness of load-duration curve. Unfortunately, the load-duration curve is bounded in practice. Von der Fehr and Harbord (1993) proposed a model with a step-like supply function. They showed that for some patterns of demand and allocation of capacity among generators there would be no equilibrium in pure strategies. Klemperer and Meyer (1989) and Baldick, Grand, and Kahn (2004) showed the case with multiple equilibriums.

The existence of a unique equilibrium is a very important issue in the application of any oligopoly game theory, including SFE models. An equilibrium exists if there are mutually consistent actions that all market players will not deviate from it in order to maximize their profit. Multiple equilibriums could be present when there exist several such mutually consistent actions. If the equilibrium could be reached through a consistent set of deterministic actions, it is called pure strategy equilibrium. If it can be reached through a set of probabilistic actions of players, it is called mixed strategy equilibrium. The practice is more interested in the pure strategy equilibrium. If a unique equilibrium exists, it is reasonable to assume that the interactive among market players might eventually drive the market to reach the equilibrium. Therefore, if there is a unique equilibrium, the SFE model should be appropriate to predict the likely outcome of the market. If there are multiple equilibriums, the calculated equilibriums could not provide a convincing prediction of market outcome (stoft (1997)).

Even though the practical value of SFE model is challenged by the multiple equilibriums problem, it is less problematic when the practical issues, such as capacity constraints, price caps (Holmberg (2004), Baldick, Grant, and Kahn (2004)), or multiple time periods are considered (Baldick, Grant, and Kahn (2004)). Green and Newbery (1992) note that capacity constraints tend to limit the range of equilibriums. Baldick and Hogan (2002) investigated the effect of capacity constraints, price caps, and the length of the time horizon over which bids must remain unchanged. They empirically confirmed that the range of equilibriums could be very small when there are moderately tight capacity constraints and price caps.

Stability of equilibrium further alleviated the problematic of multiple equilibriums in practice (Baldick and Hogan (2002)), because only stable equilibrium could be sustained in actual market. For unstable equilibrium, the best responses of the players will deviate much from the equilibrium given arbitrarily small perturbations to the supply functions from the equilibrium. Unstable equilibrium is not expected in practice due to the high uncertainty factors in actual electricity market, such as the volatility of demand and transmission outages.

Baldick and Hogan (2002) not only emphasized the importance of equilibrium stability, but also justified the advantage of the linear supply function over other general form. They showed that only linear SFEs are stable when there are no capacity constraints and the firms are symmetric with linear marginal costs. Their numerical simulations of asymmetric firms showed the circumstances where SFEs that are less competitive than the linear SFE are unstable. As well as this merit of stability, the linear SFE also has the advantage of being able to handle asymmetric structure with more than two strategic players. Since the asymmetric case is more interesting for practical applications, the linear SFE turns out to be attractive in practice. Rudkevich (1999) presented a model to analyze the ability of players to adapt their behavior through market observations and proved that players characterized with linear marginal costs and unconstrained capacities are capable of converging to the linear SFE. Baldick, Grant and Khan (2004) applied the linear SFE to the electricity market in England and Wales and showed that the linear case seems to fit the actual price in the E&W market reasonably.

Through all the above development, linear SFE models have become a good tool to understand how market power could be exercised in the electricity market and estimate the possible result from market power. The empirical applications of SFE models to the England and Wales market and the California market did show their helpfulness to understand the mechanism that market power could be exercised and the result market power could bring to the markets. Therefore, we choose the linear SFE model as the framework to investigate firms' bidding strategies with forward contracts.

It is well known that the special features of electricity transmission systems can have important effects on the equilibrium solution in electricity market (Berry (1999), Hobbs (1999), Oren (1997), Smeers and Jing-Yuan (1997), Cardell (1997)). A central contribution of this dissertation is the incorporation of transmission constraints into the linear SFE framework.

In order to test our model, we apply it to simulate the bidding behaviors in the ERCOT market, where about 95%-97% of the end energy is traded through bilateral contracts. The application is helpful to the ERCOT market, which differs from SMD and other electricity markets in many aspects. Some of the findings in other restructured markets may not be suitable for the ERCOT market reality because of its different market structure. Furthermore, ERCOT is currently undertaking a market redesign rulemaking process. Understanding market power issues in its current market is important and instructive for this policy process.

4.3 MODEL FORMULATION

Market players have both incentive and ability to affect prices in spot markets. At close to real time, both supply and demand become inelastic. Electricity cannot be stored and generators have limits on how quickly they can be started, and ramped up or down. Because the time-varying wholesale price is neither seen nor paid by end-use consumers, suppliers face a nearly vertical demand curve. Therefore, the profit from market manipulation is greatly increased as the market moves closer to real time.

Forward contracts enable buyers and sellers to lock their prices and quantities in advance of the real-time, which reduces the profit from increases in real-time prices. Hence, forward contracts play an important role in reducing incentives to exercise market power and hedging the risk related to the high volatility of prices in real-time markets (Powell (1993) and Borenstein (2001)).

In electricity markets, electric firms compete through both spot market bidding and bilateral contract trading. Firms have to consider their forward contract positions when they make spot market decisions. In this chapter, we propose a linear asymmetric Supply Function Equilibrium (SFE) model with transmission constraints to develop firms' optimal bidding strategies considering forward contracts. The characteristics of firms' behaviors and the mitigation effects of forward contracts are analyzed for different situations under the induced equilibrium conditions. Based on Baldick, Grant, and Kahn (2004), Xu, and Yu (2002), Newbery (1998), and Green (1999), the linear SFE model with forward contracts is constructed as follows for the transmission un-congested case in section 4.3.1 and for the transmission congested case in section 4.3.2.

4.3.1 Transmission un-congested model

Assume there are m firms. The forward contract obligation for firm j during time period T is denoted as F_{jT} at forward price P_{jT}^{c}. Each firm $j \in \{1,...,m\}$ submits a bid curve that is assumed to apply throughout time period T. The bid curve $q_j : [P_{\min}, P_{\max}] \to [0, U_j]$ for time period T is defined by:

$$q_j(p) = \beta_j(p - \alpha_j), \tag{4.1}$$

where $P_{\min}$, $P_{\max}$, and U_j are the minimum and maximum bid price cap, and generation capacity.

The total production cost function C_j is assumed to be a convex quadratic function, which depends on linear marginal cost functions:

$$C_j(q_j) = 0.5 d_j q_j^2 + a_j q_j . \tag{4.2}$$

The system demand curve is assumed to be:

$$D_t = N(t) - \gamma p_t , \tag{4.3}$$

where $N(t)$ is the load-time function, representing the load at time $t \in T$; γ is related to the demand elasticity.

The market clearing condition is:

$$\sum_{k=1}^{m} q_j(p_t) = D_t . \tag{4.4}$$

Since the supply functions are non-decreasing and the market clearing price is the same for all players when there is no transmission congestion, this market clearing condition maximizes the (revealed) social welfare.

Therefore, the profit function for firm j at time t is:

$$\pi_{jt} = p_t q_j(p_t) - C_j(q_j(p_t)) - F_{jT}(p_t - P_{jT}^c) . \tag{4.5}$$

At equilibrium, each player's optimal supply function is the best response to the supply functions of its competitors within feasible function space. That is, the equilibrium q_j^* satisfies:

$$\pi_{j,t}(q_j^{\ *}(p_t), q_{-j}^*(p_t)) \geq \pi_{j,t}(q_j(p_t), q_{-j}^*(p_t)) ,$$

where $q_{-j}^*(p_t)$ represents competitors' supply functions.

Because forward contracts are decided before the spot market, spot market prices cannot directly affect the forward contract obligation F_{jT} and the forward price P_{jT}^c. Differentiating the profit function with respect to price:

$$\frac{d\pi_{j,t}}{dp_t} = q_j(p_t) - (p_t - C_j^{\ \prime}(q_j(p_t))(\frac{dq_j(p_t)}{dp_t}) - F_{jT} + \frac{d(P_{jT}^c F_{jT})}{dp_t} . \tag{4.6}$$

Setting (4.6) equal to zero to obtain the optimal price using the market clearing condition (4.4), we have:

$$q_j^*(p_t) - F_{jT} = (p_t - C_j^{\ \prime}(q_j^*(p_t))\left(-\frac{dD_t}{dp_t} + \sum_{k \neq j}^{m} \frac{dq_k^*(p_t)}{dp_t} \right). \tag{4.7}$$

Substituting (4.1) and (4.2), we have:

$$\beta_j(p_t-\alpha_j)-F_{jT}=(p_t-d_j\beta_j(p_t-\alpha_j)-a_j)(\gamma+\sum_{k\neq j}^{m}\beta_k). \tag{4.8}$$

A solution to coupled condition (4.8) of all firms is an SFE.

Since the bid function is required to be consistent during period T, equation (4.8) should be satisfied for the realized prices during that time period. If there are at least two levels of demand cleared during the period T, then there will be at least two prices realized and (4.8) will be satisfied as an identity as Baldick, Grant, and Kahn (2004). Consequently, the coefficient of price p_t on the left hand and right hand of (4.8) should be equal, and similarly the constant term should be equal. Therefore, the conditions for an SFE are:

$$\beta_j=(1-d_j\beta_j)(\gamma+\sum_{k\neq j}^{m}\beta_k), \qquad \forall j, \tag{4.9}$$

$$\beta_j\alpha_j-F_{jT}=(a_j-d_j\beta_j\alpha_j)(\gamma+\sum_{k\neq j}^{m}\beta_k), \qquad \forall j. \tag{4.10}$$

Substitute (4.9) into (4.10), we have:

$$\alpha_j=a_j-(\frac{1}{\beta_j}-d_j)F_{jT}, \qquad \forall j. \tag{4.11}$$

From (4.9) and (4.11), we observe that the slope of the SFE does not depend on the amount of forward contract F_{jT}, but the intercept α_j does depend on F_{jT}. When $F_{jT}=0$, the intercept of a firm's SFE is equal to the intercept of its marginal cost function:

$$\alpha_j=a_j, \qquad \forall j. \tag{4.12}$$

Rearranging (4.11) yield:

$$\alpha_j+\frac{1}{\beta_j}F_{jT}=a_j+d_jF_{jT}=C'(F_{jT}), \qquad \forall j. \tag{4.13}$$

This means the SFE will intersect the marginal cost function at the position of the contract obligation, which is consistent with the observations in Green (1999), Newbery (1998), and Anderson and Xu (2002).

Figure 4.1 shows the SFEs for the above cases. The marginal cost function is shown in the Figure as MC. SF1 is for the no-forward contract case, which has the same intercept as the marginal cost function MC, but a different slope. For the case with forward contracts, we denote the quantity of forward contracts as F_T. B denotes the point on MC with quantity F_T. SF2 represents the SFE for the contracted case, which goes through B and has the same slope as SF1.

In Figure 4.1, forward contracts move the SFE downward by the distance between A and B, which indicates the market power mitigation effects of forward contracts. From Figure 4.1, we can see that the greater the amounts of forward contracts, the more mitigation effects. However, we observe that strategic firms still bid at a higher price than their marginal cost to sell energy in excess of their contracted quantity and at a lower price than their marginal cost to buy energy from the spot market, which is consistent with the findings in (Green (1999) and Newbery (1998)).

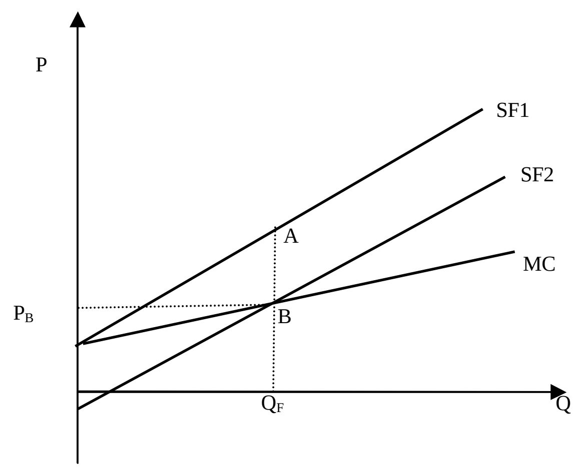

Figure 4.1: Supply Functions with Forward Contracts

4.3.2 Transmission Congested model

We still use the DC power flow model discussed in Chapter 3 to represent the transmission network. Assume there are n nodes and K transmission lines in the system. Firms are indexed by the node numbers of their locations. If there are multiple generation firms at a node, artificial nodes could be defined. Therefore, we can assume that there is only one firm at each node. Load nodes could be treated similarly to locate them at different nodes from generators. Nodal angles, nodal generation, nodal load and transmission capacities are denoted by vectors $\boldsymbol{\theta}$, $\mathbf{q}$, $\mathbf{D}$, and $\mathbf{FL}_{\max}$, respectively.

Then, as in Chapter 3, the DC power flow and transmission capacity constraints are:

$$\mathbf{S}(\mathbf{q}-\mathbf{D}) \leq \mathbf{FL}_{\max},$$

where, $\mathbf{S}=\mathbf{HB}^{-1}$, $\mathbf{B}$ is the imaginary part of the nodal admittance matrix, $\mathbf{H}$ is the product of the branch susceptance diagonal matrix and an appropriate incidence matrix of branches with nodes.

We maintain the same assumptions for firms as in Section 4.3.1, except that we use nodal prices, since the nodal price will be different if there is any transmission line congested. In order to facilitate the discussion, we use the inverse form of supply functions:

$$p_{jt} = \frac{1}{\beta_j} q_{jt} + \alpha_j = \kappa_j q_{jt} + \alpha_j, \tag{4.14}$$

where $\kappa_j = 1/\beta_j$.

Each firm's decision process has to consider the market-clearing process of the system operator, which is constrained by transmission capacities and firms' generation limits. The problem is described as the following bi-level optimization process:

$$Max \quad \pi_j \tag{4.15}$$

$$Min \sum_{i=1}^{n} (\int_0^{q_i} (p_i(q)dq - \int_0^{D_i} (p_i(D)dD) \tag{4.16}$$

$$s.t. \quad \sum_{i=1}^{n} (q_i - D_i) = 0, \tag{4.17}$$

$$\mathbf{S}(\mathbf{q}-\mathbf{D}) \leq \mathbf{FL}_{\max}, \tag{4.18}$$

$$\mathbf{0} \leq \mathbf{q} \leq \mathbf{q}_{\max}, \tag{4.19}$$

Model (4.16)-(4.19) describes the market clearing process performed by the system operator, which is to maximize system welfare (or minimize negative welfare) constrained by system supply and demand balance (4.17), transmission capacities (4.18) and firms' generation limits (4.19).

We assume that when bidding into the spot market, it is known whether or not a line is going to be constrained based on the forward contract decisions and other information that becomes available before the spot market. In contrast, if the binding/non-binding determination is endogenous, generally speaking, there will not be a pure strategy equilibrium in either the Cournot or SFE framework. Mixed strategy equilibrium approaches could be applied to deal with the endogenous case, which is beyond the scope of this paper. Here we assume that the information about binding constraints is exogenous. Therefore, we can include only the binding constraints in the formulation of the Lagrangian for the market clearing problem and treat binding constraints as equality constraints. In order to highlight forward contracts and transmission constraints, we do not consider generator capacity limits here. Then the Lagrangian for the market clearing problem is:

$$L = \sum_{i=1}^{n} \left(\int_0^{q_i} p_i(q)dq - \int_0^{D_i} p_i(D)dD \right) + \lambda \left(\sum_{i=1}^{n} (q_i - D_i) \right) + \boldsymbol{\mu}_b^T (\mathbf{S}_b \hat{\mathbf{q}} - \mathbf{FL}_{b\max}), \tag{4.20}$$

where λ and $\boldsymbol{\mu}_b$ are Lagrange multiplier vectors for the system balance constraint and binding transmission constraints, respectively, and $\mathbf{S}_b$ and $\mathbf{FL}_{b\max}$ are the shift factor matrix and capacity limit vector for the known binding transmission constraints. Vector $\hat{\mathbf{q}} = \mathbf{q} - \mathbf{D}$ represents the net nodal injection.

By the first order condition of the Lagrangian (4.20), the optimal solution $\mathbf{z}^* = [\hat{\mathbf{q}}^{*T}, \lambda^*, \boldsymbol{\mu}_b^{*T}]^T$ satisfies:

$$\begin{bmatrix} \boldsymbol{\beta} & \mathbf{1} & \mathbf{S}_b^T \\ \mathbf{1}^T & \mathbf{0} & \mathbf{0} \\ \mathbf{S}_b & \mathbf{0} & \mathbf{0} \end{bmatrix} \begin{bmatrix} \hat{\mathbf{q}} \\ \boldsymbol{\lambda} \\ \boldsymbol{\mu}_b \end{bmatrix} = \begin{bmatrix} -\boldsymbol{\alpha} \\ \mathbf{0} \\ \mathbf{FL}_{b\max} \end{bmatrix}, \tag{4.21}$$

where $\boldsymbol{\beta}$ is a diagonal matrix consisting of the slopes of inverse SFEs and consumer marginal benefit functions, $\boldsymbol{\alpha}$ is a vector containing the intercepts , $\mathbf{1}$ is a vector with all elements equal to 1. Equation (4.21) can be simplified as:

$$\mathbf{wz} = \mathbf{g}. \tag{4.22}$$

According to Xu and Yu (2002), the sensitivity of the optimal solution $\mathbf{z}^*$ with respect to the slope of supply function for firm j is:

$$\partial \mathbf{z}^* / \partial \kappa_j = -\mathbf{w}^{-1}\mathbf{I}_j \mathbf{z}^*, \tag{4.23}$$

$$\partial \mathbf{z}^* / \partial \alpha_j = -\mathbf{w}^{-1}\mathbf{1}_j, \tag{4.24}$$

where $\mathbf{I}_j$ is a square matrix with 1 for its $j\,th$ diagonal element and 0 for other elements, and $\mathbf{1}_j$ is a vector with only one non-zero element of 1 for element j.

By (4.24), we have

$$\frac{\partial q_{jt}^*}{\partial \kappa_j} = -\xi_{jj} q_{jt}^*, \tag{4.25}$$

$$\partial q_{jt}^* / \partial \alpha_j = -\xi_{jj}, \tag{4.26}$$

where ξ_{jj} is the j th diagonal element of $\mathbf{w}^{-1}$.

The profit function for firm j is:

$$\pi_{jt} = (\kappa_j q_{jt} + \alpha_j)(q_{jt} - F_{jT}) - 0.5 d_j q_{jt}^2 - a_j q_{jt} + F_{jT} P_T^c \ . \tag{4.27}$$

By (4.25) and (4.26), the first order conditions of (4.27) are:

$$\partial \pi_{jt} \big/ \partial \kappa_j = q_{jt}^{*2} - [(2\kappa_j - d_j) q_{jt}^* + (\alpha_j - a_j - F_{jT}\kappa_j)]\xi_{jj} q_{jt}^* - F_{jT} q_{jt}^* = 0, \tag{4.28}$$

$$\partial \pi_{jt} \big/ \partial \alpha_j = q_{jt}^* - [(2\kappa_j - d_j) q_{jt}^* + (\alpha_j - a_j - F_{jT}\kappa_j)]\xi_{jj} - F_{jT} = 0. \tag{4.29}$$

Rearranging (4.28) and (4.29), we get:

$$((1 - (2\kappa_j - d_j)\xi_{jj}) q_{jt}^{*2} - (\alpha_j - a_j - F_{jT}\kappa_j)\xi_{jj} q_{jt}^* - F_{jT} q_{jt}^* = 0, \tag{4.30}$$

$$(1 - (2\kappa_j - d_j)\xi_{jj}) q_{jt}^* - (\alpha_j - a_j - F_{jt}\kappa_j)\xi_{jj} - F_{jt} = 0. \tag{4.31}$$

Note that these equations should be satisfied for all time during period T. Assume that at least two different dispatches happen during time period T. Comparing (4.30) to (4.31), we observe that (4.30) will be satisfied as long as (4.31) is satisfied. Similar to the un-congested case, we assume that at least two different dispatches are realized during period T. Then by setting, respectively, the coefficients of q_{jt}^* and the constant term of (4.31) to zero and rearranging, we obtain equilibrium conditions:

$$1 - (2\kappa_j - d_j)\xi_{jj} = 0, \tag{4.32}$$

$$\alpha_j = a_j - F_{jT}(\kappa_j - d_j), \tag{4.33}$$

where we have used (4.32) to simplify the terms in (4.33).

By comparing (4.32) and (4.9), we observe that the transmission *constraints* affect the slopes of the SFEs. However, forward *contracts* do not affect the slopes of the SFEs for both the transmission un-congested and the transmission congested cases. Comparing (4.11) and (4.33), we observe that the intercepts are similar, which means forward contracts have similar effects on the intercepts of SFEs for the transmission congested case as for the transmission un-congested case.

By checking (4.32) and (4.33), we found the slope of SFE does not change with forward contracts, but the intercept will change. When $F_{jT} = 0$, the intercept of a firm's SFE equals to the intercept of its marginal cost function:

$$\alpha_j = a_j \,. \tag{4.34}$$

Rearranging (4.34) yields:

$$\alpha_j + \kappa_j F_{jT} = a_j + d_j F_{jT} = C'(F_{jT}) \,. \tag{4.35}$$

This means SFE will intersect the marginal cost function at the position of the contract obligation. Therefore, forward contracts have the same effects on firms' optimal strategy for transmission-congested case as for the un-congested case that was discussed in Section 4.3.1.

An iterative method can be developed based on (4.32) and (4.33) to calculate the SFEs with transmission congestion under forward contracts. But we should note that the binding transmission constraints are assumed not to change during the iteration. Otherwise, this method will fail to converge, which indicates that the SFE does not exist in strict sense.

In electricity markets, Transmission Congestion Rights (TCRs) are a special form of forward contracts provided for market participants to hedge the risk of congestion prices. A TCR entitles its holder to get payment based on the difference between nodal prices or the shadow price on the congested line. Therefore, the profit of firm j 's TCRs can be expressed as:

$$T_j(p_t) = \sum_{i=1}^{n} r_{ji}\, p_{it} \,, \tag{4.36}$$

where r_{ji} is related to the quantity of firm j 's TCR involving node i. If the net TCR ownership involving node i is from other nodes to node i, then r_{ji} is positive. Otherwise, it is negative.

The profit function for firm j with TCRs is:

$$\pi_{jt} = (\kappa_j q_{jt} + \alpha_j) q_{jt} - 0.5 d_j q_{jt}^2 - a_j q_{jt} + T_j(p_t) . \tag{4.37}$$

The conditions for SFE can be obtained following similar steps to the case for forward contracts. That is, analogously to (4.30) and (4.31), we have:

$$(1-(2\kappa_j - d_j)\xi_{jj})q_{jt}^{*2} + r_{jj}q_{jt}^* - (\alpha_j - a_j + r_{ji}\kappa_j)\xi_j q_{jt}^* - \sum_{i\neq j}^{n} r_{ji}\kappa_i \xi_{ij} q_{it}^* = 0, \tag{4.38}$$

$$(1-(2\kappa_j - d_j)\xi_{jj})q_{jt}^* + r_{jj} - (\alpha_j - a_j + r_{jj}\kappa_j)\xi_j - \sum_{i\neq j}^{n} r_{ji}\kappa_i \xi_{ij} = 0, \tag{4.39}$$

where ξ_{ij} is the element of $\mathbf{w}^{-1}$ at (i, j) position.

By (4.38) and (4.39), we found that the slope and intercept of a firm's SFE are affected by its TCR shares. Here we only discuss the simplest case to illustrate possible strategies related to TCRs. It is assumed that $\xi_{ij} = 0, \forall i \neq j$. This assumption means firm j has very little effect on the prices of nodes except the node i where it is located. Therefore, we can ignore the terms related to nodes other than node j in (4.38) and (4.39), and the slope of SFE is the same as (4.32), but the intercept changes to:

$$\alpha_j = a_j + r_{jj}(\kappa_j - d_j) . \tag{4.40}$$

As a result, if r_{jj}>0, it may be profitable for the firm to increase the intercept of its SFE to increase the TCR value by increasing the shadow price. In contrast, if r_{jj}<0, it may be profitable for the firm to decrease its intercept.

Now we assume that firm j owns generation units on both node j and node k, and owns a TCR from node j to node k. We now assume that the firm cannot significantly affect the prices at nodes $i \neq j, k$. The shadow price on line from node j to node k is related to $(p_k - p_j)$ so that $r_{jj} < 0$, $r_{jk} > 0$. Analogously to the previous case, the firm may increase the intercept of its SFE at node k and decrease its intercept of SFE at node j to increase the shadow price on the line and therefore increase its profit.

4.4 APPLICATION

Since most of energy is traded through bilateral contract markets in the ERCOT wholesale market, it is instructive to apply the proposed SFE model with forward contracts to the ERCOT real-time BES market to gain insight into bidding behaviors of market participants under forward contracts. In this section, we discuss the assumptions for the application of the proposed SFE model to simulate the ERCOT market. Then the simulation results are presented and discussed. The related information to the software in this application is provided in the appendix.

4.4.1 Assumptions about ERCOT SFE model with forward contracts

1) ***Forward Contract***

The ERCOT market design encourages forward transactions between market participants. The real time energy accounts only 3% - 5% of the end energy consumption. Without considering forward contracts, the SFE model of the ERCOT real-time market will overestimate the effect of oligopoly market power.

When we consider the effect of forward contracts, we assume the profit from forward contracts is not affected by real-time market prices. It is because the forward contract prices are set before the real-time market. The long-term effect of real-time market on the forward contract is not considered in this dissertation. However, it can be extended in the future research based on the theoretical framework developed in section 4.3. The balancing energy bid activities of a player depends only on their profit or cost from selling or buying BES in the real-time market. Under this assumption, a competitive supplier would like to sell their excess capacity excluding their forward contract to the BES market if MCPE is higher than its cost, and would like to buy energy from the BES market to satisfy its contracted load obligation if the MCPE is below its costs.

Unfortunately, there is no public resource about the actual forward contract positions of firms in ERCOT. We assume the schedules submitted by QSEs match their forward contracts between generation resources and LSEs. However, schedules could be manipulated to affect MCPEs. In this case, our SFE model will underestimate the effect of market power.

2) ***Strategic Players***

In a perfectly competitive BES market, a firm should bid their marginal cost around its contract obligation as its BEU and BED bids. If a firm has market power, it can be expected to bid higher BEU price than marginal cost for offer in excess of its forward contracts to sell energy and bid BED price lower than marginal cost to buy energy as we discussed in Section 4.3.

Some firms could have market power and are able to affect the price level of the market. So firm-level oligopoly analysis will be helpful to understand their behaviors and market results. However, the firm-level schedules and bids information are not available. Schedules and bids are submitted by QSEs in the ERCOT BES market. A QSE can represent more than one firm and submit schedules and bids for them. Since the schedules and bids in ERCOT are submitted as aggregates by QSEs, we identify QSEs as the market players even though a QSE can represent more than one firm.

Major strategic players are identified by their actual BES bid and deployment shares. Table 4.1 shows the average bid and deployment shares for the major four QSEs from January 2002 to April 2003 in the ERCOT real-time balancing energy market. The bid share is the percentage of the bid quantity from a specific QSE divided by the total system bid quantity, which is based on the hourly bid curves submitted by QSEs. The deployment share is the percentage of the quantity deployed to a specific QSE over the total system deployed quantity, which is based on the actual first-step deployment information. Because the MCPEs are decided based on the first-step portfolio deployment during our test time period, unit specific deployments in the second-step for local congestion management is not considered.

Table 4.1: Bid and Deployment Shares

QSE Name	BEU Shares		BED Shares	
	Bid	Deployment	Bid	Deployment
TXU	44.7%	24.8%	25.1%	13.1%
Texas Genco	24.8%	21.2%	28.2%	35.1%
Calpine	5.1%	14.6%	7.3%	12.4%
AEP	8.6%	8.8%	9.8%	3.3%
Others	16.9%	30.8%	29.6%	36.2%

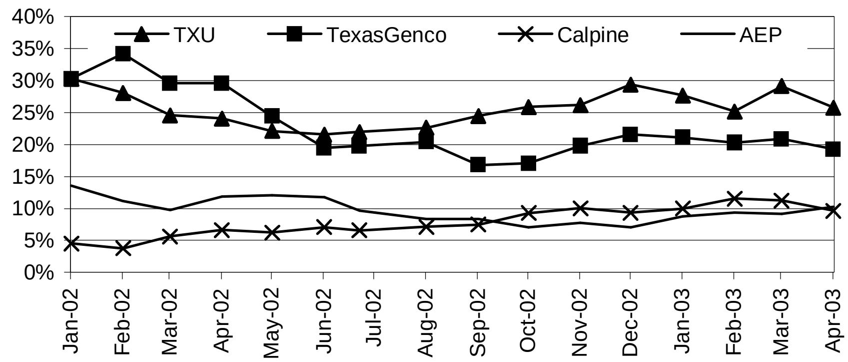

Figure 4.2: BED Bid Shares

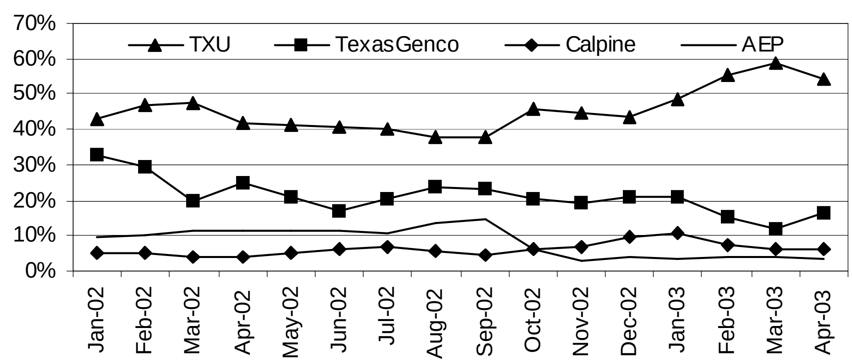

Figure 4.3: BEU Bid Shares

Figure 4.2 and Figure 4.3 shows the monthly average BED and BEU bid shares for the four biggest QSEs. Table 4.1 shows that the four biggest QSEs account for about 83.2% of bid capacity for BEU on average and about 70.4% for BED on average. They supply about 69.2% BEU and 63.8% BED demand on average in the BES market during the test period. The other 44 QSEs contribute only about 16.9% and 29.6% of BEU and BED bid capacity, respectively. They supply about 30.8% BEU and 36.2% BED demand. Since they consist of a bunch of small players, they should be represented as a competitive player. However, by the weighted average bid prices of these players, we found that some of them bid high BEU price and low BED price. In addition, we find that the assumption about these players to be a competitive fringe or a strategic player does not change the result much because of their small market share. Therefore, we represent those other QSEs as one strategic player in the SFE model. The monthly average BES bid shares and weighted average (WAVG) bid prices for some QSEs in ERCOT during our test time period are summarized in Table 4.2.

Table 4.2: Bid Shares and WAVG Bid Price ($/MWh) of QSEs

Name of QSEs	Bid Shares BEU	WAVG Price BEU	Bid Shares BED	WAVG Price BED
TXU	44.7%	65	25.1%	1
Texas GenCo	24.8%	82	28.2%	-5
American Electric Power	8.6%	44	9.8%	-27
Calpine Power Mangement	5.1%	46	7.3%	-210
Coral Power	2.6%	43	3.8%	-52
ANP	1.8%	28	3.1%	-257
Lower Colorado River Authority	1.6%	55	3.6%	-20
Automated Power Exchange	1.6%	56	2.9%	-367
FPL Energy	1.6%	32	1.7%	-182
Dynegy Power	1.2%	43	2.2%	-44
Mirant Americas	1.0%	170	1.9%	-261
FPLE	0.8%	33	1.1%	-213
Aquila Energy	0.5%	26	2.0%	-223
City of Garland	0.4%	46	0.8%	4
South Texas Electric Coop	0.2%	30	0.4%	-60
PG and Energy Trading	0.1%	177	0.5%	-10

Actually the major four QSEs represent the five biggest firms in ERCOT, including TXU generation company, Reliant energy, Calpine, City Public Service of San Antonio (CPS), and Central power and light (CPL) which is an affiliate of American Electric Power. Texas GenCo includes both reliant and CPS. American Electric Power (AEP) includes CPL in its portfolio. These five firms consist about 24%, 18%, 8%, 6%, and 5% of the system installed capacity, respectively. We tried our SFE model with 3-8 players, the results keep consistent and the differences is within 1%.

3) ***Demand***

Most of the SFE models in the literature focus on the Pool market or the day-ahead market. In this kind of market, the load duration curve (Klemperer and Meyer (1989), Green and Newbery (1992)) is used to characterize electricity demand over a day. In the real-time market, it is hard for load duration curve to capture the high volatility of balancing energy demand. The BES consists of only small part of system end energy consumed. Table 4.3 shows the monthly statistics of BES percentage over total system energy consumption in ERCOT. There is uncertainty imbedded in how much BES will be deployed and whether BEU or BED will be deployed. Figure 4.3 and Figure 4.4 shows the monthly BES deployed quantity and number of intervals for BEU and BED deployment. That is, instead of a load duration curve, a probability distribution is appropriate to represent the variation of demand in the real-time market, as used in the original development of Klemperer and Meyer (1989).

Table 4.3: BES Percentage of System Energy

Month	Mean		Min		Max	
	BEU	BED	BEU	BED	BEU	BED
Jan-02	2.5%	1.7%	0.4%	0.2%	4.5%	4.7%
Feb-02	1.4%	1.9%	0.2%	0.4%	4.7%	5.5%
Mar-02	1.0%	2.0%	0.0%	0.5%	4.9%	7.5%
Apr-02	0.6%	3.1%	0.0%	0.0%	2.8%	5.4%
May-02	0.7%	3.0%	0.0%	0.2%	5.0%	8.7%
Jun-02	0.9%	2.1%	0.1%	0.9%	3.0%	4.5%
Jul-02	2.1%	1.2%	0.2%	0.1%	4.7%	4.1%
Aug-02	1.9%	1.0%	0.3%	0.1%	3.4%	3.3%
Sep-02	1.9%	1.1%	0.6%	0.1%	3.6%	2.8%
Oct-02	1.8%	1.1%	0.0%	0.3%	4.6%	6.6%
Nov-02	2.3%	0.7%	0.0%	0.0%	3.9%	3.5%
Dec-02	2.3%	0.8%	0.5%	0.1%	4.0%	2.8%
Jan-03	2.2%	1.0%	0.4%	0.0%	5.4%	3.1%
Feb-03	5.0%	0.3%	0.0%	0.0%	11.0%	1.4%
Mar-03	3.4%	2.0%	0.3%	0.0%	10.7%	5.9%
Apr-03	2.0%	1.7%	0.4%	0.3%	4.5%	5.9%

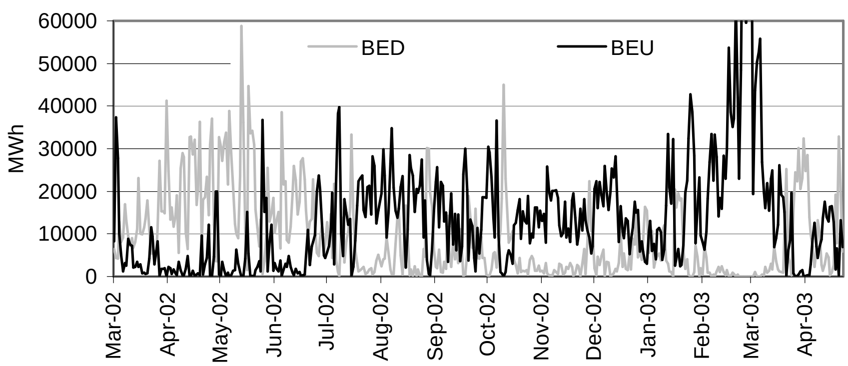

Figure 4.4: BES Daily Deployment Quantity

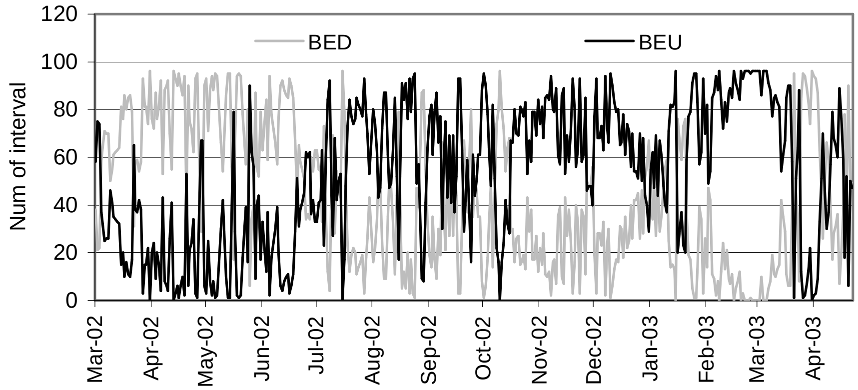

Figure 4.5: BES Daily Deployment Interval Number

The real-time balancing energy demand depends on many factors, such as the generation schedules, load schedules, the ISO's load forecasts, ancillary services purchased and deployed, and automatic system frequency control system. In addition, system demand has to be satisfied at real-time to maintain system reliability. There is no demand elasticity at real-time. Therefore, we use the actual balancing energy demand for each interval during our test period for the demand in the model assuming that the demand realizations have been drawn from a random distribution.

4) ***Marginal Cost Functions***

The production cost of each major QSE is based on the units within its portfolio. Since more than 90% of QSEs' installed capacities consist of fossil fuel units, we only consider fossil fuel units to construct the production cost functions for QSEs. As in Chapter 3, the output from other kinds of units, including nuclear, hydro, and wind units, are deducted from the respective portfolio schedule, and their effects on CSCs are based on their output.

For fossil fuel generation units, the production cost for each unit is based on the fuel price and its average heat rate as in Chapter 3. The average heat rate for each unit in ERCOT is obtained from (Henwood (2002), EPA (2002), and PUCT (2002)). The gas prices are obtained from the Market Oversight Division (MOD) at the Public Utility Commission of Texas (PUCT). Coal prices are from (EIA (2002b)). The capacity of a unit is based on its installed capacity considering its forced outage probability (NERC (2002)).

The intercept and slope for a QSE's marginal cost function are obtained by linearly approximating its marginal cost curve. For the QSEs with both coal and gas units, piece-wise linear marginal cost functions are constructed to capture the cost jump from coal to gas technology with two sets of parameters for coal and gas units respectively.

However, the linear marginal function does not capture the rapid increase in marginal cost at high output close to the maximum capacity. Since ERCOT has high capacity reserve margin, the capacity limits normally are not constrained. So the linear approximation for the part close to the capacity limit will not affect the result much. No attempt is made to capture the operating, planned maintenance, environmental cost, and ancillary services purchased in ERCOT day-ahead market. Those factors could result in underestimation of the marginal costs.

5) ***Capacity Limits***

In the ERCOT BES market, the maximum BEU capacity a QSE can supply is its maximum installed generation capacity minus its scheduled generation. The maximum BED capacity a QSE can supply is its scheduled generation quantity[5]. Actually QSEs bid only part of their available BES capacity, less than 15% for BEU and 30% on average for BED during the test period as shown in Table 4.4.

[5] Relaxed balanced schedule allows QSEs to schedule more generation than their actual needs resulting in some of the scheduled generation be used in the BES market.

Table 4.4: QSEs Bid Percentage (Bid Quantity/Capacity)

Month	TXU		GenCo		AEP		Calpine		Others	
	BEU	BED	BEU	BED	BEU	BED	BEU	BED	BEU	BED
Jan-02	13.3%	28.2%	8.9%	30.2%	10.3%	28.2%	4.4%	11.1%	4.9%	19.6%
Feb-02	13.2%	24.2%	6.9%	32.5%	9.3%	26.6%	4.1%	9.6%	3.3%	20.2%
Mar-02	12.8%	26.5%	4.9%	26.5%	10.6%	24.7%	3.3%	15.0%	6.7%	24.8%
Apr-02	12.1%	27.1%	6.9%	25.2%	12.0%	29.7%	3.7%	15.1%	7.6%	22.9%
May-02	14.0%	23.2%	6.3%	20.9%	13.3%	30.9%	6.5%	16.3%	10.4%	28.7%
Jun-02	16.3%	20.4%	5.7%	16.8%	16.5%	29.6%	9.6%	18.8%	13.4%	34.1%
Jul-02	19.0%	20.4%	8.6%	16.0%	15.0%	32.9%	14.8%	16.2%	14.1%	34.6%
Aug-02	20.9%	19.4%	11.2%	16.2%	19.5%	31.8%	13.9%	16.8%	15.0%	31.4%
Sep-02	17.6%	21.2%	9.3%	14.0%	20.1%	28.0%	8.9%	16.9%	13.1%	31.8%
Oct-02	13.4%	24.9%	5.4%	15.8%	5.3%	23.6%	9.4%	16.7%	9.5%	29.0%
Nov-02	11.1%	25.0%	4.4%	18.0%	2.3%	26.8%	8.8%	17.9%	8.9%	25.9%
Dec-02	11.4%	23.3%	5.1%	16.1%	3.4%	17.3%	10.4%	19.0%	7.8%	34.8%
Jan-03	14.6%	20.2%	5.1%	19.0%	3.0%	28.6%	12.2%	23.3%	6.9%	23.1%
Feb-03	18.3%	22.4%	4.0%	20.3%	3.8%	27.8%	10.5%	24.1%	9.3%	23.2%
Mar-03	15.9%	30.5%	2.5%	20.0%	3.7%	29.3%	8.1%	23.6%	8.1%	21.6%
Apr-03	12.4%	24.7%	3.4%	16.2%	2.3%	33.6%	5.5%	25.1%	7.2%	22.3%
Average	14.8%	23.8%	6.2%	20.2%	9.4%	28.1%	8.4%	17.8%	9.2%	26.8%

The small bid capacities may be a sigh of physical withholding. However, firms might have reasons for not bidding all their BES capacity, such as unit commitment decisions, operation preference, and fuel supply limitations. In order to avoid detailed consideration of these factors, we assume the actual bid quantity of each QSE is its actual available quantity considering all its individual conditions. When we relax bid limits based on their installed capacity and schedules, the changes of our SFE price results are less than 3%, because only about 17% and 23% on average of the BEU and BED bid quantity were actually deployed during our test time period as shown in Table 4.5.

Table 4.5: Percentage of Deployed BES/Bid Quantity

Month	BED			BEU		
	Average	Max	Min	Average	Max	Min
Jan-02	17.6%	65.9%	2.2%	21.2%	64.7%	2.2%
Feb-02	14.6%	57.5%	1.9%	20.4%	96.4%	1.2%
Mar-02	14.5%	89.4%	0.6%	17.9%	90.8%	2.0%
Apr-02	21.2%	56.5%	2.4%	20.6%	67.8%	2.1%
May-02	19.6%	70.7%	1.8%	19.3%	62.3%	1.9%
Jun-02	15.8%	51.3%	1.9%	21.2%	80.6%	2.6%
Jul-02	17.6%	53.3%	3.6%	27.2%	74.6%	2.6%
Aug-02	17.3%	43.9%	4.2%	23.8%	84.2%	1.6%
Sep-02	18.1%	38.9%	5.0%	20.3%	72.5%	3.5%
Oct-02	18.7%	44.4%	6.3%	22.8%	96.8%	4.8%
Nov-02	17.2%	79.2%	4.1%	21.7%	72.8%	5.1%
Dec-02	18.4%	65.6%	2.8%	24.1%	83.8%	2.7%
Jan-03	14.4%	64.0%	2.2%	20.2%	77.7%	1.8%
Feb-03	9.9%	41.7%	2.1%	29.3%	93.6%	2.5%
Mar-03	19.1%	94.7%	2.9%	23.9%	99.9%	1.6%
Apr-03	16.5%	61.8%	2.2%	24.3%	90.3%	2.7%
Average	17.4%	94.7%	0.6%	23.0%	99.9%	1.2%

6) ***Transmission Congestion***

Transmission congestion is a source of market power. In the ERCOT SFE model, we consider only the CSC congestion, because MCPEs depend on CSC congestion, not local congestion during our test time period. Monthly zonal weighted average shift factors are used to represent the effect of zonal generation and load on CSCs.

The ERCOT ISO publishes the possible binding constraints before real-time based on the information submitted to the ISO from QSEs. We assume that the real-time market has a small enough effect so that no expected non-binding constraints will become binding due to balancing deployment. Therefore we assume that it is known in advance whether or not a line is going to be constrained in the real-time market, and only include binding constraints in (4.21) for the ERCOT application.

Although allocations of TCRs and PCRs can affect market power related to congestion as we discussed in Section 4.3.2, there is no public resource of information about them in ERCOT. We assume a QSE's TCR shares are consistent with its forward contracts. However, its actual TCR shares may be higher or lower than its forward contracts, which may result in underestimation or overestimation of market power for the congested cases. The generators of each major QSE player in each zone are treated as one player for the congested case.

4.4.2 Results

In the application of the proposed SFE model to simulate the ERCOT real-time market, an hourly supply function is formed for each of the major players based on (4.9) and (4.11) for transmission un-congested hours and (4.32) and (4.33) for transmission congested hours during January 2002 to April 2003. For every 15 minutes interval, the market is cleared according to market clearing condition (4.4). When some BEU bid prices are lower than some BED bid prices (called overlap) (ERCOT (2002b)), they are cancelled against each other to ensure that most efficient resources are deployed. There was overlap for about 43% of intervals during the test period.

Some intervals were excluded from the calculation in order to avoid the influence of abnormal events, such as forced outages, software failures, and operational errors (ERCOT (2003a)). There are a total of 464 intervals excluded from the total 46560 intervals for the testing time period, which account for only about 0.9 % of the total test intervals.

The simulation was performed with Matlab 6.5 on a Linux workstation with a 1.8GHZ Xeon processor. All information related to congestion, transmission limits, actual market prices, demand, and schedules are available at (ERCOT (2003a)). The computation took less than 0.1 second on average for an un-congested case, and about 28 seconds on average for a congested case.

1) ***Transmission un-congested case***

There are about 83% of intervals without transmission congestion during our test period. The monthly weighted average marginal cost (MC), the estimated SFE prices for non-contracted case (SFE_NC) and contracted case (SFE_C), and the actual market prices are listed in Table 4.6 for the transmission un-congested cases. Table 4.6

also shows weighted average price (WAP) and the weighted average percentage of price-cost margin (PC Margin) over the test time period. Since the no-contracted case is a pure pool market case, only BEU would be deployed in such a market. Therefore, the no-contracted case is only listed for the BEU market for these transmission un-congested cases.

From Table 4.6, we see that forward contracts decrease estimated SFE price-cost margin by 13.3%, from 17.3% to 4.0%, which indicates the market power mitigation effect of forward contracts. The counter-factual SFE BEU non-contracted prices are usually higher than both the SFE contracted prices and the actual market prices. Comparing contracted SFE prices with the actual market prices, we find that the average SFE BEU contracted price of $51.10/MWh matches the average actual market price of $53.17/MWh very well, with a -3.9% difference between them.

Table 4.6: Results of SFE Transmission Un-congested Case

Month	BEU ($/MWh)				BED ($/MWh)		
	MC	SFE_NC	SFE_C	Actual	MC	SFE_C	Actual
Jan-02	21.22	24.93	20.97	21.11	22.04	20.84	7.71
Feb-02	21.73	27.98	21.74	21.10	22.09	20.78	9.89
Mar-02	28.17	34.57	28.20	32.77	27.52	26.38	13.22
Apr-02	33.73	40.46	33.89	35.94	31.51	29.47	17.48
May-02	32.69	38.75	33.62	34.52	32.95	31.81	15.17
Jun-02	33.21	41.56	34.64	33.67	31.72	30.58	16.75
Jul-02	30.82	39.38	32.38	32.86	29.31	28.25	16.64
Aug-02	30.98	39.90	32.45	30.46	31.24	30.38	17.22
Sep-02	34.93	42.41	35.74	31.82	33.78	33.24	14.95
Oct-02	37.82	43.74	38.30	41.71	34.39	33.84	17.16
Nov-02	36.54	40.52	36.44	35.35	34.11	34.48	14.00
Dec-02	43.57	48.83	43.80	40.23	39.97	40.40	11.73
Jan-03	51.81	60.20	53.00	52.50	48.44	47.79	17.74
Feb-03	86.74	101.47	92.94	103.54	46.39	48.23	19.26
Mar-03	67.08	76.32	69.58	71.81	42.39	41.57	30.73
Apr-03	50.57	58.54	52.46	57.85	40.73	43.54	15.16
WAP	49.14	57.64	51.10	53.17	33.37	32.58	16.16
PC Margin	-	17.3%	4.0%	8.2%	-	2.4%	-51.6%

Several factors may contribute to the difference. First, firms' actual bids could involve a much more complicated asset optimization process than the SFE model. A firm can include their fuel supply, environmental constraints, forced or planned outage, volatility of demand, and operational issues into consideration. In addition, their actual marginal cost and bid curves could be more complicated than our linear supply functions. We assume each QSE is one player, which may actually include several competing firms. The ERCOT ISO considers operational constraints such as ramp rate in the market clearing process, which we do not consider because this information is not available publicly. The relatively low price cost margin (8.2%) of the actual BEU price indicates an efficient BEU market performance.

In contrast, the average SFE BED price of $32.58/MWh does not fit the actual BED price of $16.16/MWh well. The relatively lower actual BED price indicates that some participants do not want to decrease generation in the real-time market compared to their forward contract position or schedule. In our SFE model, we assume that market players are indifferent to forward and spot markets, and they will buy energy from real-time market if there is cheaper suppliers available. However, it turns out that some market participants submitted low BED bids in order to avoid buying energy from real-time market, even when there are cheaper resources available in the real-time market. The relatively low price cost margin (-51.6%) of actual BED price suggests an inefficient BED market performance.

2) ***Transmission congested case***

There are about 16.7% transmission congested intervals during our test period. Results for the congested intervals are shown in Table 4.7. Table 4.7 shows similar market mitigation effects of forward contracts, decreasing SFE price-cost margin by 15.4% from 21.8% down to 6.4%, as observed for the transmission un-congested cases. The difference between the average estimated SFE contracted price of $37.91/MWh and actual BEU price of $43.05/MWh is about -11.9%, while the difference between average SFE BED contracted price of $29.02/MWh and actual BED price of $16.09/MWh is 80.4%. These differences between the estimated contracted SFE prices and the actual market prices are somewhat larger than for the transmission un-congested cases, and the price cost margins are slightly different.

Several factors could contribute to the different rates. CSC congestion, as discussed in Section 4.3 is an obvious one. In addition, we did not consider the effects of TCR or PCR assignment because this information is not available publicly. However, as we discussed in section 4.3, players may increase or decrease their BES bids to maximize their profit from both energy trading and TCRs. Then the SFE prices considering TCRs could be higher for the BEU and lower for the BED than the SFE prices without considering TCRs shown in Table 4.7. Therefore, if the TCRs information is available, the gap between our SFE results and actual market prices for the congested case may be improved.

Table 4.7: Results of SFE Transmission Congested Case

Month	BEU ($/MWh)				BED($/MWh)		
	MC	SFE_NC	SFE_C	Actual	MC	SFE_C	Actual
Jan-02	21.06	24.50	21.04	24.23	22.30	19.72	4.97
Feb-02	21.57	27.05	27.98	35.78	21.76	19.28	9.11
Mar-02	28.32	35.19	28.76	30.45	27.90	24.23	12.28
Apr-02	35.51	45.61	37.17	79.77	32.59	28.26	17.33
May-02	33.59	39.23	33.98	33.32	35.23	31.21	16.73
Jun-02	33.31	42.37	35.57	36.82	32.37	31.99	19.48
Jul-02	30.72	39.62	32.98	33.58	29.56	28.72	16.41
Aug-02	32.55	43.12	35.00	34.28	31.37	31.01	19.56
Sep-02	35.49	45.18	38.32	38.53	35.71	35.04	18.47
Oct-02	40.05	51.38	43.43	52.57	36.33	31.20	23.22
Nov-02	33.01	39.90	39.01	40.10	30.42	19.17	15.84
Dec-02	43.87	49.00	44.46	41.44	41.69	43.79	29.54
Jan-03	54.61	65.17	56.99	52.23	49.69	47.68	20.51
Feb-03	75.13	85.32	78.98	63.93	57.70	56.90	26.97
Mar-03	64.61	73.06	67.18	86.19	47.27	45.23	36.72
Apr-03	50.08	58.98	52.79	74.77	47.59	45.45	22.90
WAP	35.63	43.39	37.91	43.05	31.29	29.02	16.09
PC Margin	-	21.8%	6.4%	20.8%	-	7.3%	-48.6%

Although SFE prices deviate from the actual market prices by different amounts for the congested intervals and for the un-congested intervals, the overall weighted average SFE BEU contracted price of $49.00/MWh still matches the actual BEU price of $51.56/MWh well for the whole test period as shown in Table 4.8. It is because the congested intervals account for only about 15% of the all intervals during the test time.

In contrast, the estimated SFE BED average price of $31.87/MWh is not close to the actual BED price of $16.15/MWh. The overall price cost margin for the BEU and BED actual prices are 9.8% and –50.9% respectively, which indicate relatively efficient BEU market and inefficient BED market performance respectively in the ERCOT balancing energy market during the test time period.

Table 4.8: Results of SFE for the Test Period

Month	BEU ($/MWh)				BED($/MWh)		
	MC	SFE_NC	SFE_C	Actual	MC	SFE_C	Actual
Jan-02	20.86	24.70	21.01	22.66	22.03	20.38	6.59
Feb-02	21.51	27.58	24.32	27.16	21.78	20.35	9.67
Mar-02	28.05	34.68	28.30	32.34	27.46	26.14	13.11
Apr-02	34.20	41.84	34.77	47.70	31.38	29.15	17.44
May-02	32.71	38.77	33.64	34.47	33.03	31.73	15.38
Jun-02	33.27	41.92	35.06	35.07	31.86	31.10	17.74
Jul-02	30.83	39.45	32.56	33.07	29.29	28.43	16.55
Aug-02	31.34	40.52	32.94	31.20	31.24	30.55	17.85
Sep-02	35.09	43.09	36.37	33.46	34.03	33.55	15.56
Oct-02	38.05	44.33	38.69	42.54	34.43	33.76	17.34
Nov-02	36.53	40.52	36.45	35.38	34.05	34.39	14.01
Dec-02	43.57	48.84	43.83	40.28	39.97	40.41	11.74
Jan-03	51.86	60.30	53.08	52.49	48.46	47.79	17.78
Feb-03	86.39	101.02	92.55	102.43	46.47	48.30	19.31
Mar-03	66.47	75.66	69.10	74.70	42.68	41.76	31.04
Apr-03	50.53	58.59	52.50	59.83	42.04	43.89	16.57
WAP	46.97	55.37	49.00	51.56	32.82	31.87	16.15
PC Margin	-	17.7%	4.3%	9.8%	-	-3.4%	-50.9%

Several issues can contribute to the relatively efficient BEU market. The high volume of forward contracts decreases the incentive of major market players to raise real-time market prices. If forward contract volume decreases, real-time BEU price may increase. The high capacity reserve margin of ERCOT (34% for 2002 and 21% for 2003) presumably also contributes to the relatively efficient BEU market as we discussed in Chapter 3.

The inefficient performance of BED market may be caused by the following factors. Technical limits, such as unit commitment, low generation limits, and operational constraints can result in relatively high adjustment costs that make firms not willing to decrease their generation levels. This, on the other hand, may also indicate the inefficiency of their forward decisions, or difficulty in adjusting their forward decisions. Currently ERCOT is undergoing a market redesign process. A day-ahead energy market will be implemented for the new market, which will be helpful to improve the efficiency of forward contract decisions. However, the mitigation effect of forward contracts will decrease if market players decrease their forward contracts. Furthermore, some firms may not want to expose themselves to the real-time market opened three years ago, and hold some of their capacity to cover their native load in case of any unexpected situation. Another possibility is that the small profit from the low transaction volume in the ERCOT real-time market does not out-weigh the cost for changing their previous practices before the real-time market opened.

4.5 CONCLUSIONS

An asymmetric linear Supply Function Equilibrium model with transmission constraints is proposed to develop firms' optimal bidding strategies given their forward contracts. Equilibrium conditions are derived and discussed for different situations.

The proposed model is applied to simulate the bidding behavior in the real-time balancing energy market of ERCOT from January 2002 to April 2003. Market power mitigation effects of forward contracts are evaluated. The estimated contracted SFE prices match the actual market prices of balancing up energy well. However, the actual average balancing down energy prices is found to be much lower than the estimated contracted SFE prices, which indicates that some market participants did not choose to buy available cheaper energy in the real-time market to supply their contract obligations. Adjustment costs, hedging risk costs, and other individual consideration may contribute to the unwillingness of some participants to decrease their generation output in the real-time market.

Competitive forward contract markets and a day-ahead market will be helpful to increase the efficiency of forward decisions. If the volume of forward contracts decreases, the market price of real-time balancing up energy may increase because the mitigation of forward contracts will decrease.

Our model can be used to analyze the effect of different level forward contracts on real-time market prices. It can also be extended to analyze the interaction between day-ahead market and real-time market, the market power related to TCRs, or estimation of the possible market results with different ownership structure in the future.

CHAPTER 5: SUMMARY AND FUTURE RESEARCH

5.1 SUMMARY

In this dissertation, models are developed to analyze the electricity market efficiency and bidding strategies of market participants. Because the physical characteristics of electric power have important effects on the electricity markets, the proposed models emphasize on the transmission constraints. A principal contribution of this dissertation is the incorporation of transmission constraints into the competitive benchmark evaluation. Another principal contribution of this dissertation is the incorporation of transmission constraints and transmission congestion rights into a numerically tractable SFE framework. These models are applied to simulate the ERCOT real-time balancing energy market from January 2002 to April 2003.

For the models estimating the competitive benchmark, transmission constraints and operational constraints, which are neglected in most of the empirical literature, are considered. Although the competitive benchmark approach can evaluate market performance, it cannot provide the reasons for the market inefficiency. Many issues can contribute to the market inefficiency, such as market design flaws, market power, and inherent engineering features of power system operations. This dissertation focuses on the effects of transmission and operational constraints on the market efficiency first. Models are developed to estimate how transmission and operational constraints affect market prices based on the actual market bids.

These market efficiency analysis models are applied to the efficiency analysis of the ERCOT real-time energy market by simulating its operation from January 2002 to April 2003. The ERCOT market is undertaking a market redesign rulemaking process. Evaluation of the performance of its current market is helpful for this policy process. The results show that the balancing up energy market is relatively efficient, and the balancing down energy market is relatively inefficient during the test period. It is also found that transmission congestion had more impact on the market performance than did operational constraints. However, operational constraints and CSC congestion did not contribute much to the relatively uncompetitive performance of the balancing down energy market. This indicates that the bid behavior of market participants contributes to the most of the performance of the balancing down energy market.

A linear asymmetric SFE model with transmission constraints is proposed to analyze the bidding strategies with forward contracts. In electricity markets, firms compete through both spot market bidding and bilateral contract trading. Firms have to consider their forward contract positions when they make spot market decisions. The proposed SFE model is used to develop firms' optimal bidding strategies with the consideration of forward contracts both for energy and transmission. The characteristics of firms' behaviors are analyzed for different situations under the induced equilibrium conditions. The model contributes to the literature in several aspects. First, forward contracts, transmission constraints, and multi-period strategy (an obligation for firms to bid consistently over an extended time horizon such as a day or an hour) are integrated into the linear asymmetric SFE framework. As an ex-ante model, it can provide qualitative insights into firms' behaviors. Second, the bidding strategies related to Transmission Congestion Rights (TCRs) are discussed by interpreting TCRs as linear combination of forwards. Third, the model is a general one in the sense that there is no limitation on the number of firms and scale of the network, which can have asymmetric linear marginal cost structures.

In addition to the theoretical analysis based on the SFE model, we apply our SFE model to simulate the bidding behavior in the ERCOT real-time market. Most applications of oligopoly models focus on contract markets or day-ahead pool markets. Our model shows that the real-time market analysis is also valuable even when it is relatively small in trading quantity. The simulated SFE prices for balancing up energy services match the actual market prices well. In contrast, the estimated SFE prices for balancing down energy services do not match the actual market prices well, which indicates some market participants do no like to change their forward contract position through real-time market, even though there are cheaper supplies available. The adjustment costs, hedging risk cost, and other individual consideration may contribute the unwillingness of generators to take part in the real-time balancing down market in ERCOT during the test time period.

Several issues can contribute to the relatively efficient BEU market. The high volume of forward contracts decreases the incentive of major market player to raise real-time market prices. If forward contract volume decreases, real-time BEU price may increase. The high capacity reserve margins in ERCOT presumably also contributed to the competitive performance of the BEU market. Several circumstances, including the transmission interconnection rules and the renewable energy credit-trading program, have encouraged significant new generation investments in ERCOT since 1995. The reserve margins were 34% and 21% for 2002 and 2003, respectively.

The inefficient performance of BED market may be caused by the following factors. Technical limits, such as unit commitment, low generation limits, and operational constraints can result in relatively high adjustment costs that make firms not willing to decrease their generation levels. This, on the other hand, may also indicate the inefficiency of their forward decisions, or difficulty in adjusting their forward decisions. Furthermore, some firms may not want to expose themselves to the real-time market opened three years ago, and hold their capacity to cover their native load in case of any unexpected situation. Another possibility is that the small profit from the low volume real-time market does not out-weigh the cost for changing their previous practices before the ERCOT real-time market opened.

Three-part bid (energy, start-up, and no load cost bid), centralized unit-commitment, competitive forward contract markets, and day-ahead energy market could be helpful to increase the efficiency of market participants' forward decisions. Market power mitigation for balancing energy bids will also be helpful to limit the deviation of major players' bids from their marginal costs.

5.2 FUTURE RESEARCH

Although the empirical analysis in this dissertation focus on the ERCOT real-time market, the proposed general theoretical models for the market efficiency and bidding strategy analysis in this dissertation are applicable to the market analysis with different market structures, including the one that ERCOT market will possibly become and the transitional period from current market structure to the new market structure.

The proposed models can also be extended to study other issues important in electricity markets:

- Unit commitment can be included in the process for the marginal cost estimation for the system or a market participant, which will extend the models by considering the unit start up or shunt down characteristics;
- Market power related to transmission congestion (ownership of transmission congestion rights) can be analyzed based on the framework in Chapter 4;
- Based on the long-term relationship of real-time market prices and contract prices, the equilibrium between day-ahead market and real-time market can be analyzed;
- The effects of different contract level on spot market can be evaluated by changing the contract level;
- The possible market results from different divesture structure.

APPENDIX A COMPUTATIONAL ISSUES

A.1 INTRODUCTION

This dissertation analyzes the real-time ERCOT BES energy market data in an attempt to find the underline behavior of the market and its participants. Extensive computations have been performed in this process. However, as long as producing correct data, the computational procedures themselves are of less importance comparing to the model construction, data, and information extraction. To keep the discussion of market insights from being disrupted, we omit all the computational issues in the chapters, and give a description of them in this appendix.

The computation in this dissertation mainly involves optimization problems such as solving nonlinear equations and math programming problems with integral-type objective functions. Some statistical procedures are also performed to extract useful information from a large amount of data. In this appendix, we will first give a brief description of the computer environment, in which the computations have been performed. Then we describe a linear programming approach to solve the math programming problems with integral-type objective functions.

A.2 COMPUTATIONAL ENVIRONMENT

Major computations are performed with MATLAB 6.5 on a Linux workstation (with 1GB memory and a 1.8GHz Xeon processor). To solve optimization problems, we also use the Optimization Toolbox (version 2.3) that came with the MATLAB.

The raw data for this dissertation came in the form of Microsoft Excel files. Other statistical computations and data clean work are performed with MS Excel and MATLAB on a PC with a 2.4GHz Pentium 4 processor.

A.3 A LINEAR PROGRAMMING APPROACH

In this dissertation, we constantly need to nonlinear math programming problems in the following form:

$$Minimize \sum_{i=1}^{n} C_i(q_i), \tag{A1}$$

subject to:

$$\begin{aligned} \mathbf{Aq} &\le \mathbf{b} \\ \mathbf{0} \le \mathbf{q} &\le \mathbf{u} \end{aligned} \tag{A2}$$

where $C_i(q_i)$ is a continuous nonlinear function with non-decreasing derivative on q_i.

This problem can be solved as a general nonlinear constrained optimization problem. However, due to constraints, it usually takes a long time to solve, and the results tend to be inaccurate. We propose to reform the problem into a linear programming problem, which can be solved with high accuracy with modern algorithms. The resulting linear problem has much more variables, yet can be solved much faster with high accuracy.

We define the following variables:

$$0 \le x_{ij} \le 1,\ j = 1,\ldots,u_i, i = 1,\ldots,n.$$

Then the new linear programming problem needs to be solved is:

$$Minimize \sum_{i=1}^{n}\sum_{j=1}^{u_i} \alpha_{ij} x_{ij}, \tag{A3}$$

subject to:

$$\text{(A2) with } q_i \text{ being replaced by } \sum_{j=1}^{u_i} x_{ij},\ i = 1,\ldots,n, \tag{A4}$$

where $\alpha_{ij} = C_i(j) - C_i(j-1),\ j = 1,\ldots,u_i, i = 1,\ldots,n$.

After solving this linear programming problem, the solution to (A1-A2) is:

$$q_i = \sum_{j=1}^{u_i} x_{ij}, i = 1,\ldots,n. \tag{A5}$$

This result follows from the fact that $C_i(q_i)$ has non-decreasing derivative on q_i, $i = 1, \ldots, n$.

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This dissertation was typed by the author with Microsoft Word.